Economic Project Appraisal Manual for Kenya

Case Energy Infrastructure Project (CBA)

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ABBREVIATIONS/ ACRONYMS

ADSCR	Annual Debt Service Coverage Ratio
ANPC	Annualized Net Present Cost
ANPV	Annualized Net Present Value
AR	Accounts Receivable
AP	Accounts Payable
BAC	Budget at Completion
BAU	Business-As-Usual
BCR	Benefit–Cost Ratio
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
CEA	Cost Effectiveness Analysis
CPB	Cost Per Beneficiaries
CPM	Critical Path Method
CSCF	Commodity Specific Conversion Factor
EAC	East African Community
Ee	Economic Exchange Rate
EIA	Environmental Impact Assessment
Em	Market Exchange Rate
ENPV	Economic Net Present Value
EOCK	Economic Opportunity Cost of Capital
EXT	Externalities
FEL	Front End Loading
FEP	Foreign Exchange Premium
FF	Finish to Finish
FNPV	Financial Net Present Value
FS	Feasibility Studies
FtS	Finish to Start
GDP	Gross Domestic Product
GoK	Government of Kenya
IRR	Internal Rate of Return
KES	Kenyan Shillings
KPI	Key Performance Indicators
LFA	Logical Framework Approach

LFM	Logical Framework Matrix
LLCR	Loan Life Coverage Ratio
MCA	Multi-Criteria Analysis
MDA	Line Ministries, Departments and Agencies
M&E	Monitoring and Evaluation
NGOs	Non-Government Organizations
NPC	Net Present Costs
NPP	National Priority Programs
NPV	Net Present Value
NTP	Premium on Non-tradable Outlays
OER	Official Exchange Rate
OPEX	Operational Expenditures
O&M	Operating and Maintenance
PACM	Project Alternatives Comparison Matrix
PAT	Project Alternatives Table
PCN	Project Concept Note
PEP	Project Execution Plan
PFS	Pre-Feasibility Studies
PIM	Public Investment Management
PIP	Public Investment Plan
PPP	Public Private Partnership
PDM	Precedence Diagramming Method
PtW	Permits to Work
RBS	Resource Breakdown Structure
ROI	Return on Investment
SCF	Standard/Generic Conversion Factor
SDR	Social Discount Rate
SER	Shadow Exchange Rate
SERCF	Shadow Exchange Rate Conversion Factor
SF	Start to Finish
SIA	Social Impact Assessment
SMART	Specific, Measurable, Achievable, Relevant, Time-bound
SOCC	Social Opportunity Cost of Capital
SOE	State Owned Enterprises

SPE	Strategic Planning Exercise
SPNT	Shadow Price for Non-Tradable
SPNTO	Shadow Price for Non-Tradable Outlays
SRTP	Social Rate of Time Preference
StS	Start to Start
SWOT	Strengths, Weaknesses, Opportunities and Threats
SWR	Shadow Ware Rate
SWRCF	Shadow Wage Rate Conversion Factor
UDR	Utility Discount Rate
VAT	Value Added Taxes
WACC	Weighted Average Cost of Capital
WAM	Weighted Average Method
WBS	Work Breakdown Structure

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ENERGY INFRASTRUCTURE PROJECT

Seven forks 40 MW solar power plant

1 INTRODUCTION

“Infrastructure or economic project” is a widely used term to refer to projects that are aimed to provide inputs for other projects and production processes, such as transportation, energy, telecommunications and irrigation, among others. Infrastructure projects can be funded by private companies, publicly, or combined as a public-private partnership (a collaboration of government entities and private sector companies).

Since benefits and costs for infrastructure projects can be quantified and valued in monetary terms, CBA is the right method to appraise this kind of projects. For this reason, the appraisal of infrastructure projects is a great opportunity to apply an integrated approach to intervention project analysis. The purpose of this case study is, in this context, to offer a cost-benefit economic evaluation, linked to a business model based on contracting by Public Private Partnership (PPP), which serves as an application supplement to the methodological manual for project preparation and evaluation.

The case study presented in this document is built upon the combination of varied data and cases found in the literature for illustrative purposes only, and does not represent an actual investment plan. However, the case has been constructed based on the Feasibility Study for the 40 MW Seven Forks Solar Power Plant (2018), prepared by K&M Advisors for the Kenya Electricity Generating Company Ltd. For this reason, some chapters have been directly extracted from the aforementioned report (in a summarized way); but the example has been modified, mainly in its business model to enrich the practical and replicable aspects of both the approach and the financial and economical integrated evaluation model, which has attached a parametric EXCEL model, easily modifiable by the manual´s users[1].

[1] On the other hand, the chapters that are directly collected from the feasibility report have been summarized to facilitate their reading, and only those fundamental aspects that are part of an analysis at the pre-feasibility level have been collected

The following table summarise the link between this case study´s chapters and basic information taken from the K&M study and other sources.

Chapter	Observation
Background	This Chapter is a summary of pages 62-75 of the K&M study.
Project justification	This Chapter is a summary of pages 13-37 of the K&M study.
Demand forecast and analysis	This chapter is own elaboration, based on data from Mabea (2014).
Objectives and expected outputs	This Chapter is a summary of pages 13-37 of the K&M study.
Technical analysis and alternatives	This Chapter is a summary of pages 61-141 of the K&M study.
Fiscal and financial analysis	This chapter is own elaboration, based on K&M study and different business models from international best practices (instead of a fixed annual payment, this case is constructed by direct selling to the market; as well, items such as Debt, Costs, growth rates and other assumptions were changed.
Economic and stakeholders' analysis	This chapter is own elaboration, based on K&M study (some benefits are included, as the economic benefits from CO2 emissions, fuel resources reduction, the stakeholders analysis and the implementation of several Conversion Factors).
Risk analysis	The base information comes from pages 213-235 of the K&M study. However, Sensitivity Analysis and Risk Analysis was made under the new financial and economic model developed.
Environmental and social analysis	This Chapter is a summary of pages 496 -906 of the K&M Document (Appendix L).
Implementation plan	This Chapter is a summary of pages 907-918 of the K&M study (Appendix L, P and P), corrected by the assumptions made in the financial and economic models.

2 BACKGROUND

Kenya experienced a steady economic growth from around 2002 to 2007 but soon after, the economy took a downturn due to a difficult year characterized by global financial crisis and post-election violence. Later, the real GDP regained from as low as 1.6% experienced after the post-election violence in 2007 to 5.8% in 2010. Demand for electricity has been increasing steadily since the year 2004 due to accelerated economic growth and entry of private investor in various sectors.

During normal hydrology, the effective capacity is 1,652 MW where hydro accounts for about 50 per cent of the total electricity energy supply. The distribution network entails receipt of bulk supply of electrical energy from generation or transmission network and transfer of this energy through distribution lines and distribution substations to consumers.

The electricity energy sector reform started with the unbundling of the then Kenya Power and Lighting Company into Kenya Electricity Generating Company (KenGen) in 1997 followed by the formation of Rural Electrification Authority (REA) in 2007. Kenya Electricity Transmission Company Limited (KETRACO) and the Geothermal Development Company Limited (GDC) were operationalized in 2008 as special purpose corporations to oversee extension of transmission network and speedy realization of renewable energy respectively. The KenGen and Kenya Power and Lighting Company have since undergone further partial privatization.

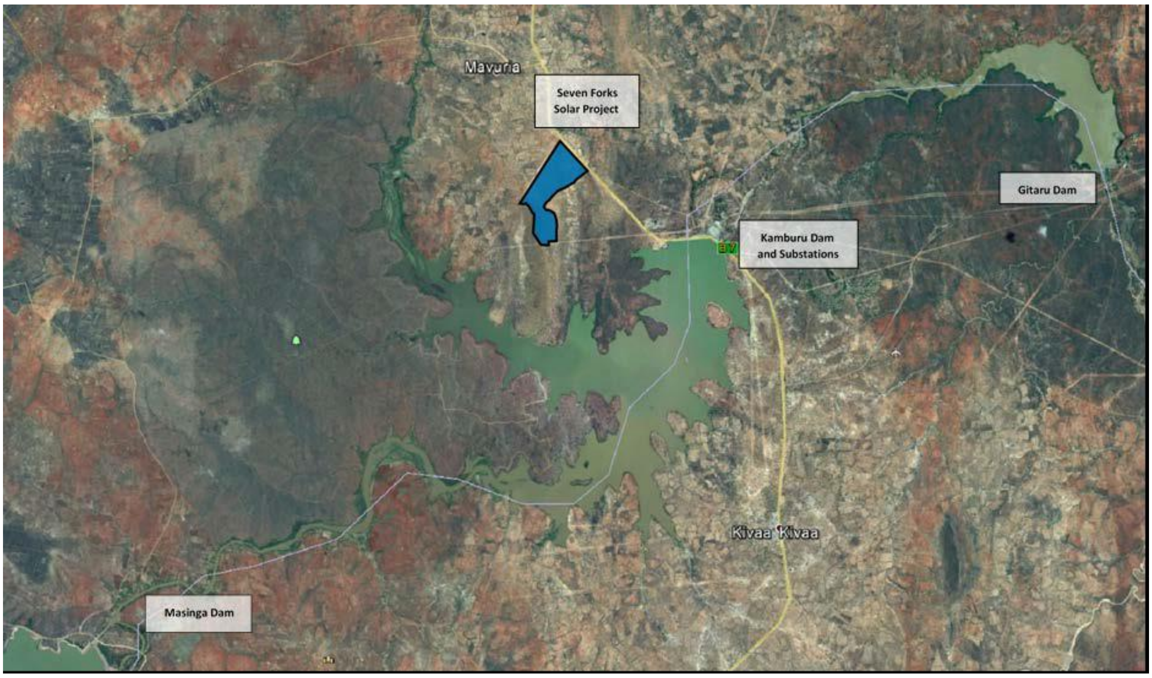
The Kenyan Government's power generation expansion plan calls for an additional 23,000 MW of capacity by 2030. This target considers current under-capacity, anticipated economic growth, and the goal of establishing a more diverse, sustainable, and robust energy matrix. As part of this growth target, the Government and other electric sector stakeholders have demonstrated strong support for renewable energy technologies including solar, wind, and geothermal. KenGen, as the leading electricity generating company in Kenya, has its own ambitious growth plan which includes multiple renewable technologies including photovoltaic ("PV") solar.

As part of the advancement of its capacity expansion plan, KenGen conducted a Prefeasibility Study (the “Study”) to examine the potential for developing a solar PV plant (the “Project”) near KenGen’s Seven Forks Hydro Station Complex (“Seven Forks”). The Study was initially based on a PV plant of approximately 10MW, which could be scaled up to 40MW in one or more phases. However, during the Study Kickoff Meeting, KenGen decided to develop a single 40MW project which would be located approximately 2.7 Km northwest of the Kamburu hydroelectric station (the “Project” or “Seven Forks Solar”).

Based on preliminary studies, KenGen identified three potential sites. The first site (“Kamburu South”) was located to the southeast of the Kamburu hydroelectric station; the second site (“Kamburu West”) was located to the northwest of the Kamburu hydroelectric station; and the third site (“Gitaru”) was to the west of the Gitaru hydroelectric station. The KenGen´s team representatives visited each site and observed that the Kamburu West site appeared to be the most suitable due to, among other things, the large area (60-70 Hectares) of relatively flat terrain and relatively limited vegetation density. KenGen subsequently selected Kamburu West as the Project site.

The Kamburu West site is wholly owned by KenGen, comprises approximately 100 Hectares, and is located approximately 160 km northeast of Nairobi and 3 kilometers northwest of the Kamburu substation in Machakos County (the “Site”). Depicted in Figure 1, the Site is bounded to the northeast by Route B7, to the northwest by a dirt road marking the perimeter of KenGen’s land, to the south by a point where gradient starts to increase and to the east by a ravine.

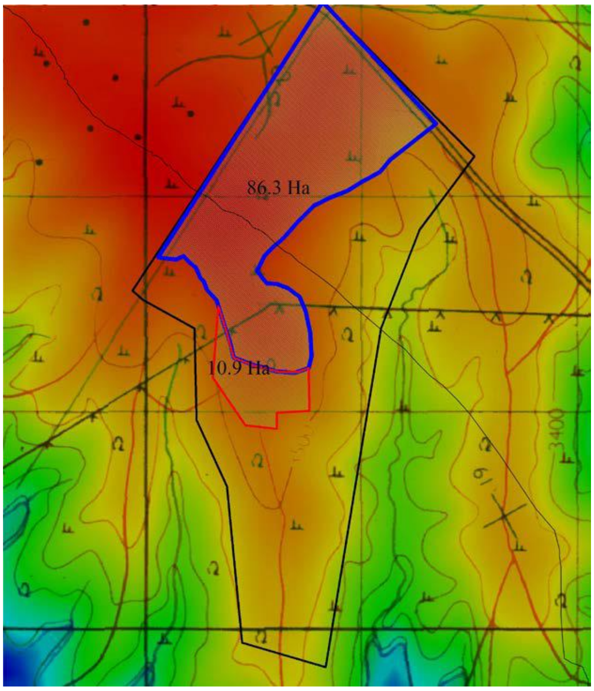
Figure 1: Project Location



Source: Google MAPS

The Kamburu West site was located to the northwest of the Kamburu Dam and is marked in green as “Priority 1 Area” in Figure 2.

Figure 2: Priority 1 Area



Source: Geological Data (2015)

The site lies approximately 3 kms from the Kamburu substation. Based on visual observations made at the center-northern portion of the site during the first visit, the land appeared to have a relatively light amount of vegetation cover and a significant area of relatively flat land with minimal visible slope. Given these encouraging characteristics, approximately 200 hectares were delineated on a map for further investigation and the team made a subsequent visit the following day with members of the Ramani land survey and Britech geotechnical teams. Figure 2 shows the recorded results with the blue lines roughly representing the borders of land that was level and red lines representing borders of land that had some moderate slope.

The color-coded overlay represents various altitudes above sea level in hundreds of meters, providing a high-level approximation of site sloping.

3 PROJECT JUSTIFICATION

The study, which will be funded by the German Development Bank KfW, will evaluate the hybrid operation of the Kamburu, Kiambere and Turkwel hydropower plants with floating solar PV to optimize water usage and power production, and contribute to a more flexible and sustainable energy system in Kenya.

The project could generate numerous benefits, most notably from the complementarity of solar production during daytime and hydropower generation during peak times in the evening, which may reduce reliance on oil/coal-fired power plants and thus reduce carbon emissions, as well as conserve water storage in the reservoirs. Large-scale floating solar plants can also reduce the evaporation rate of water, resulting in savings of water as well. The social, environmental and climate aspects and associated risks will also be assessed.

The Kamburu (94 MW) and Kiambere (168 MW) plants on the Tana river in Eastern Kenya are part of the Seven Forks cascade, which comprises five plants, with a total installed capacity of 630.5 MW. The Turkwel multipurpose dam, with an associated 106 MW hydropower plant, in north-western Kenya, impounds a reservoir covering 6500 ha with a storage capacity of 1.6×10^9 m^3.

Why is this project relevant?

Inadequate electricity generation capacity and an unreliable power supply have been perennial problems in Kenya for over a decade. As in other African countries, a lack of integration between planning and implementation has plagued the industry. Hydropower has long dominated Kenya's generating capacity and, in 2010, it supplied almost 55per cent of the country's electricity. However, severe droughts in the 1990s had virtually paralysed the industry, with the 1999 drought (the worst since 1949), leading to a 79per cent decrease in hydro capacity between July and December 2000. Power cuts were widespread and commerce and industry suffered significant losses.

While the persistent drought forced the government to introduce stopgap measures, a more fundamental reform of the electricity sector had, in fact, been initiated in 1996. This saw the establishment of an independent regulator, and the unbundling and liberalisation of the electricity sector (described in more detail later in this chapter). As a result, by 2010, Kenya had been able to attract more IPPs than any other African country. This, coupled with capacity expansion, reinforcement and electrification being undertaken by the two dominant utilities, the Kenya Electricity Generating Company (KenGen) and the Kenya Power and Light Company (KPLC), means that Kenya is well placed to overcome the challenge of inadequate and unreliable electricity supply.

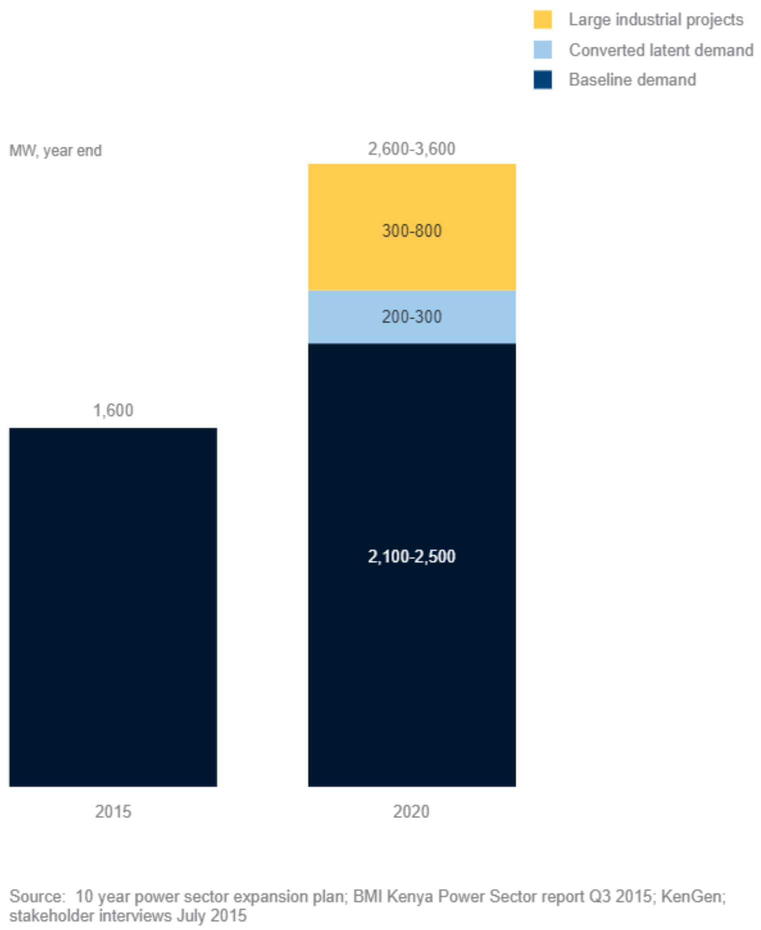
4 DEMAND FORECAST AND ANALYSIS

4.1 POWER GENERATION DEMAND FORECASTS

Power Africa's focus for this study was on enabling increased energy supply and connections. However, recognizing the importance of balancing supply and demand, Power Africa conducted a bottom-up analysis of demand. Based on this analysis, is projected power demand in Kenya to reach 2,600-3,600 MW by 2020, up to double the demand in 2015. The demand projection is based on:

- • Baseline demand from anticipated growth in population and economic activity. Based on a historical analysis, power consumption is expected to grow between 1.0-1.2x GDP growth.
- Conversion of latent demand through increased electricity access. This includes connection requests that have not yet been fulfilled. Implementation of large industrial projects, which will require significant electricity use. This is based on the Vision 2030 plan, with timelines adjusted based on interviews with government actors and private sector. Examples of such projects include the Standard Gauge Railway and LAPSSET corridor.

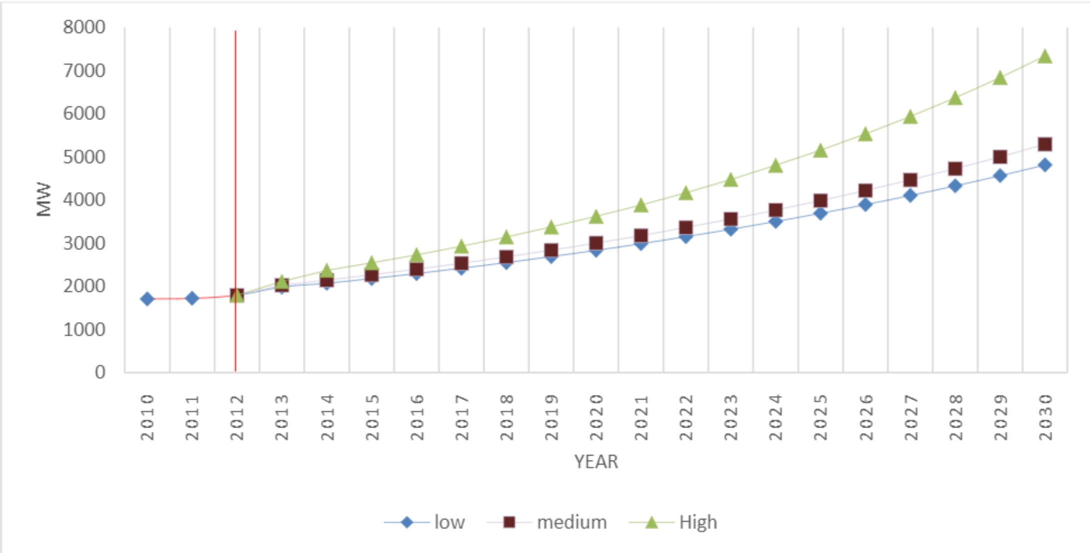
Figure 3: 2015 and 2020 MW Supply



Source: KenGen Study

The low, medium, and high scenario's peak demand forecast by the year 2030 is 4,813MW, 5,291MW, and 7,337MW respectively. Policy wise, a low scenario indicates the business as usual case with little or low economic growth. The medium term scenario indicates the ideal situation where the demand is growing steadily but with no accelerated programmes. The high scenario demand forecasts indicate the accelerated programmes enabling the achievement of the projected economic growth across all sectors.

Figure 4: Peak Demand at low, medium, and high growth scenarios



Source: Mabea, Geoffrey. (2014).

4.2 POWER GENERATION SUPPLY FORECASTS

As of August 2015, the Energy Regulatory Commission (ERC) stated that Kenya has 2,295 MW of installed on-grid capacity across 42 plants, plus an additional 11.5 MW in 19 off-grid stations in remote parts of the country.

Kenya's installed capacity consists of 70% renewable sources, with enormous potential to expand that base. According to previous studies, Kenya has the potential to produce 10,000 MW of geothermal power from the Rift Valley Basin. The United Nations Environment Program (UNEP) further estimates that Kenya's wind capacity could be as high as 3,000 MW.

Around 30% of Kenya's installed capacity is owned and operated by Independent Power Producers (IPPs) across 15 plants, including 3 small-scale hydro plants, 1 geothermal plant, 1 biomass plant, and 10 fuel oil plants. The remaining 70% capacity is owned and operated by KenGen. The actual status of Kenya's power generation capacity is shown as follows.

Table 1: Power Generation Sources at 2019

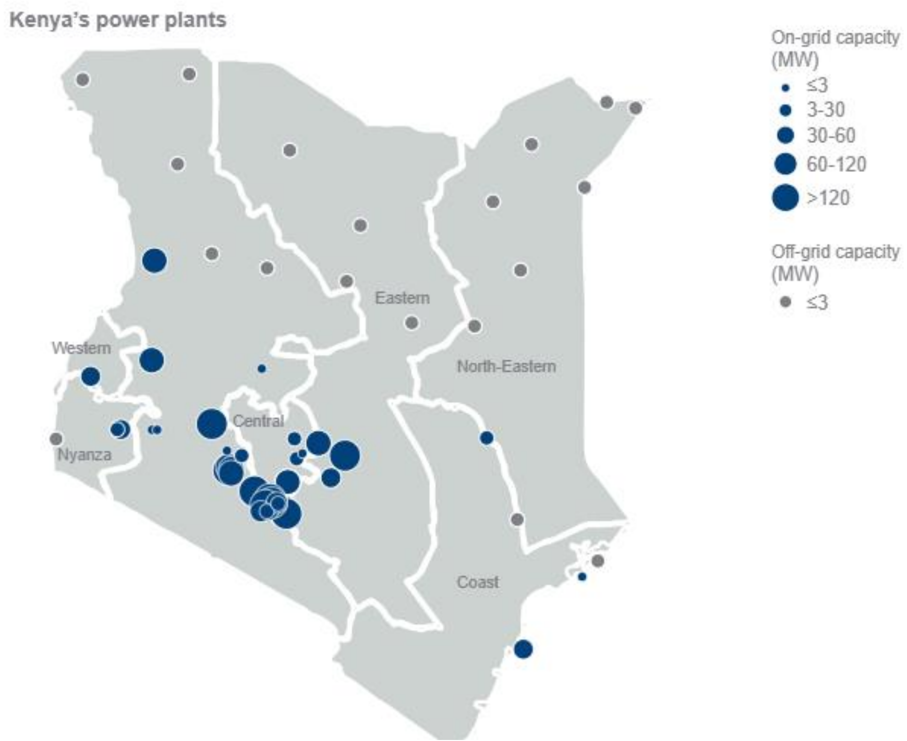
SOURCE (AS OF OCTOBER 2019)	CAPACITY (MW)	CAPACITY %
Hydro	826	29.3%
Fossil Fuels (incl. gas, diesel and emergency power)	720	25.54%
Geothermal	828	29.4%
Bagasse Cogeneration	28	0.99%
Wind	335	11.88%
Solar	50	1.77%
Others	32	1.14%
Total	2819	100.0%

Source: Energy Regulatory Commission (ERC)

Based on updated timelines and projects in the pipeline, it is estimated Kenya could have 5,040 MW of installed capacity by 2025, representing ~2,200 MW of new generation capacity coming online in 42 new plants over the next 5 years. In addition, it is estimated that all of this new capacity will be renewable energy, resulting in Kenya's energy mix being 83% renewable by 2025. Geothermal projects being developed by KenGen, GDC, and IPPs are expected to contribute 1,392 MW of new capacity. As a result, by 2020, we project geothermal will form the baseload of Kenya's power system at ~40% of all installed capacity.

By 2020, it is estimated that over 60% of Kenya's power will be generated by IPPs (including IPPs using steam provided by GDC) through 52 plants. The Government of Kenya's effort to increase generation capacity has resulted in significantly increased investment in the energy sector.

Figure 5: Kenya's power plants location



Source: Energy Regulatory Commission (ERC)

Table 2: 10 Year Power Sector Expansion Plan, 2014- 2024; Investment Prospectus

SOURCE	CAPACITY (85 PLANTS)
Geothermal	1,984 MW
Hydro	921 MW
Wind	786 MW
Fuel oil	751 MW
Solar	430 MW
Biomass	108 MW
Gas turbine	60 MW
Total	5,040 MW

Source: Energy Regulatory Commission (ERC)

The energy sector in Kenya is largely dominated by petroleum and electricity, with wood fuel providing the basic energy needs of the rural communities, urban poor, and the informal sector. An analysis of the national energy shows heavy dependency on wood fuel and other biomass that account for 68% of the total energy consumption (petroleum 22%, electricity 9%, others account for 1%). Electricity access in Kenya is low despite the government's ambitious target to increase electricity connectivity from the current 15% to at least 65% by the year 2022.

Kenya has an installed capacity of 2.3 GW. Whilst about 57% is hydro power, about 32% is thermal and the rest comprises geothermal and emergency thermal power. Solar PV and Wind power play a minor role contributing less than 1%. However, hydropower has ranged from 38-76% of the generation mix due to poor rainfall. Thermal energy sources have been used to make up for these shortfalls, varying between 16-33% of the mix.

Kenya's current effective installed (grid connected) electricity capacity is 1,429 MW. Electricity supply is predominantly sourced from hydro and fossil fuel (thermal) sources. This generation energy mix comprises 52.1% from hydro, 32.5% from fossil fuels, 13.2%

from geothermal, 1.8% from biogas cogeneration and 0.4% from wind, respectively. Current electricity demand is 1,600 MW and is projected to grow to 2,600-3600 MW by 2020. As of 2018, 6.9 million people in Kenya have been connected to the grid i.e three quarters of the total population.

Households in Kenya use the following source for lighting:

- Electricity - about 15% of the national population.
- Use of electricity in urban areas as the source of lighting - 42%; although kerosene lamps remain the main source of lighting for 55% of households.
- Kerosene for lighting in rural households - 87%

As of 2007, the contribution of the energy sector to the overall tax revenue was about 20%, equivalent to 4% of GDP. The sector provides direct and indirect employment to an estimated 16,000 persons. According to the 2019 Kenya Population and Housing Census, 50.4% total household depend on grid electricity followed by 19.3% on solar for lighting.

It costs approximately Ksh 35,000 (EUR 318.18) to connect to the national grid and about 0.1145 EUR equivalent per kWh of electricity service. These are relatively high costs that pose a major obstacle to the expansion of electricity connections to low-income households and small businesses, which can therefore benefit from decentralized alternative sources of energy, such as solar. Also, according of the Kenya National Electrification Strategy 2018, out of the 10.8 million households to be electrified, 9.7 are within the 15km of existing grid network while 1.1 million are 15km or further from the main grid and are best served by off-grid energy

Kenya has high insolation rates with an average of 5-7 peak sunshine hours (The equivalent number of hours per day when solar irradiance averages 1,000 W/m2) and receives an average daily insolation of 4-6kWh/m2. Only 10-14% of this energy can be converted into electricity due to the conversion efficiency of PV modules.

Stand-alone PV systems represent the least-cost option for electrifying homes in many rural areas, especially the sparsely populated arid and semi-arid lands. “Solar home systems” (SHSs) are practical for providing small amounts of electricity to households beyond distribution networks. The systems typically consist of a 10 – 50 Watt peak (Wp) PV module and a battery sometimes coupled with a charge controller, wiring, lights, and connections to small appliances (such as a radio, television, or mobile phones). Other PV applications include water pumping, telecommunications and cathode protection for pipelines, power supply to off-grid non-commercial establishments and off-grid small commercial establishments.

Kenya has one of the most active commercial PV system market in the developing world, with an installed PV capacity in the range of 4 MW. An estimated 200,000 rural households in Kenya have solar home systems and annual PV sales in Kenya are between 25,000-30,000 PV modules. In 2002, total PV sales were estimated to have been 750 kWp. and have grown by 170% in 8 yrs., even without government intervention or policies to promote the uptake of PV technology.

In comparison, the Kenya's Rural Electrification Fund, which costs all electricity consumers 5% of the value of their monthly electricity consumption (currently an estimated 16 million US$ annually), is responsible for 70,000 connections. With access to loans and fee-for-service arrangements, estimates suggest that the SHS market could reach up to 50% or more of un-electrified rural homes.

Since 2006-2007, the Ministry of Energy has been actively promoting use of solar energy for off grid electrification. In particular, it has funded the solar for school's programme and is targeting to extend this to off grid clinics and dispensaries. Grid connected PV systems covering an area of 15-20 km2 (3% of the Nairobi area) could provide 3801 GWh. of electrical energy a year, equivalent to the total grid electricity sales for Kenya in 2002-2003. The costs, however, are prohibitive. There are about 4 million households in rural Kenya alone which present a vast potential for this virtually untapped technology. The off-grid market is estimated to be over 40MW.

4.3 DEFICIT ESTIMATIONS

To forecast the peak demand for energy (in MW/year), the study used information generated by Mabea, Geoffrey (2014). The data was available until 2030, so the years 2031 to 2045 was constructed using the same growth rate than the used in the estimation model.

For the supply forecast, the 10 Year Power Sector Expansion Plan, 2014- 2024 was used. It was assumed that after year 2025, supply will be constant. This assumption does not take in account the new projects that have not been studied or developed, regardless that they will be developed, by the force of demand growth in time. Nevertheless, for the scope of the financial or cost benefit analysis, if the projects are not developed yet at least in a prefeasibility stage, they cannot be part of the base case scenario forecast.

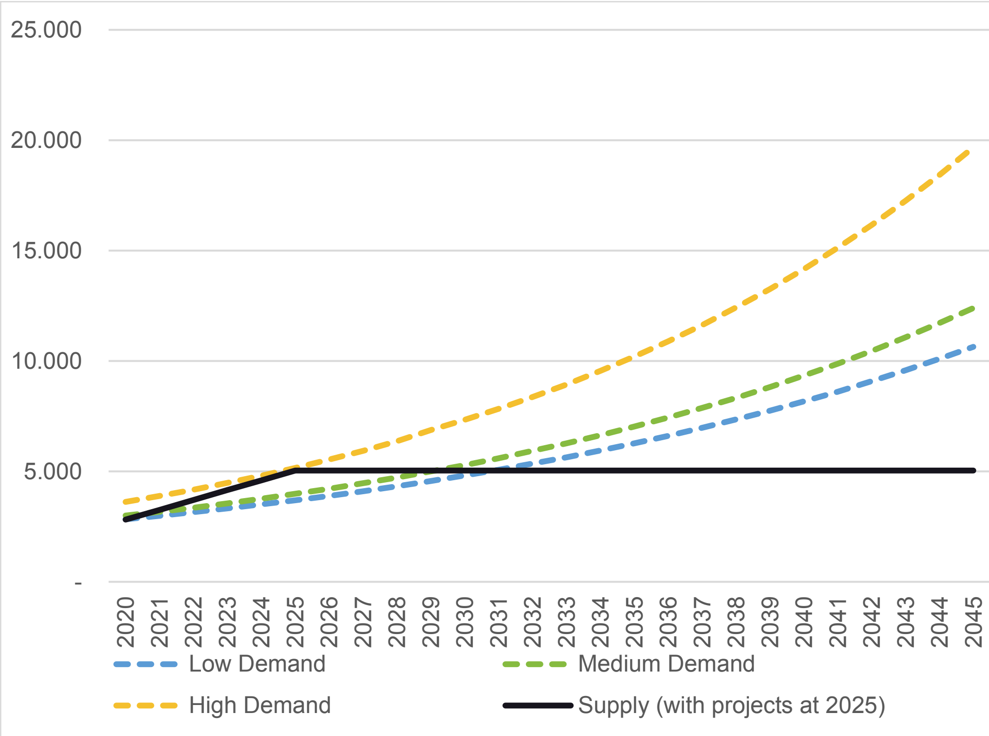
Table 3: Energy (MW) Supply and Demand from 2020 to 2042

YEAR	LOW DEMAND	MEDIUM DEMAND	HIGH DEMAND	SUPPLY (WITH PROJECTS AT 2025)
2020	2.834	3.002	3.620	2.819
2021	2.988	3.177	3.885	3.263
2022	3.151	3.362	4.169	3.707
2023	3.322	3.558	4.475	4.152
2024	3.503	3.766	4.802	4.596
2025	3.693	3.985	5.154	5.040
2026	3.894	4.218	5.531	5.040
2027	4.106	4.464	5.936	5.040
2028	4.329	4.724	6.370	5.040
2029	4.565	4.999	6.870	5.040
2030	4.813	5.291	7.337	5.040
2031	5.074	5.600	7.836	5.040

2032	5.350	5.927	8.368	5.040
2033	5.641	6.273	8.937	5.040
2034	5.947	6.640	9.545	5.040
2035	6.270	7.028	10.194	5.040
2036	6.611	7.438	10.887	5.040
2037	6.970	7.873	11.627	5.040
2038	7.349	8.332	12.417	5.040
2039	7.748	8.819	13.261	5.040
2040	8.169	9.334	14.162	5.040
2041	8.613	9.880	15.125	5.040
2042	9.081	10.457	16.153	5.040
2043	9.574	11.067	17.251	5.040
2044	10.094	11.714	18.424	5.040
2045	10.642	12.398	19.676	5.040

Source: based on Ken-Gen study.

Figure 6: Energy (MW) Supply and Demand from 2020 to 2042



Source: based on Ken-Gen study.

5 OBJECTIVES AND EXPECTED OUTPUTS

The KenGen plans to develop a photovoltaic (PV) solar power plant with a capacity of approximately 40MW on a site located within 2.5 km of KenGen's Kamburu hydroelectric power station (the "Project" or "Seven Forks Solar Project"). The development impact assessment addresses the potential impacts resulting from implementation of the Project on clean energy generation in Kenya, job creation, technology transfer, and reduction in greenhouse gas emissions.

5.1 IMPACT ON CLEAN ENERGY GENERATION IN KENYA

To provide a technical recommendation, it was conducted a technical analysis and conceptual design study for the Seven Forks Solar Project. This analysis included assessing the solar resource, establishing a conceptual plant design and technical specification, and using the results to model an estimated annual energy production for the Project in a typical meteorological year.

- **Clean Energy Generation from Seven Forks Solar Project**

The Study was initially based on a 10MWac solar project with the possibility of scaling to a higher capacity. Initially, KenGen considered the available land area and economics (including likelihood of a high voltage grid interconnection) and concluded that it would be more attractive to target a Project size of up to 40MWac. Based on KenGen's input and work, it was established a Project capacity and estimated annual energy generation, as summarized below:

Table 4: MWH Generation capacity

DESCRIPTION	VALUE
DC Capacity	47.5 MW
AC Capacity	40.0 MW (at point of interconnection)
Generation	97,219 MWh/Year

Source: based on Ken-Gen study.

KenGen's current generation capacity is dominated by hydroelectric and geothermal power and the Seven Forks Solar project would be the first utility scale Solar PV project implemented by KenGen. As KenGen aims to increase its generation capacity to 2,500 MW by 2025 from its currentcapacity of 1,631 MW[32], this PV solar project will enable the company to simultaneously grow anddiversify its portfolio.

5.2 ENVIRONMENTAL IMPACTS

The Project's environmental impacts were quantified by estimating the amount of CO2, NOX, SOX and CO avoided by reducing generation from fossil fuel fired plants. The quantity of fossil fuel generation displaced by the Project was calculated based on the Project's energy production and the average daily load and generation in Kenya (section 26.1). The amount of CO2, NOX, SOX, and CO avoided were calculated by multiplying the fossil fuel generation displaced, by theemission factors for each of these chemicals—as reported by the U.S. Environmental Protection Agency (EPA).

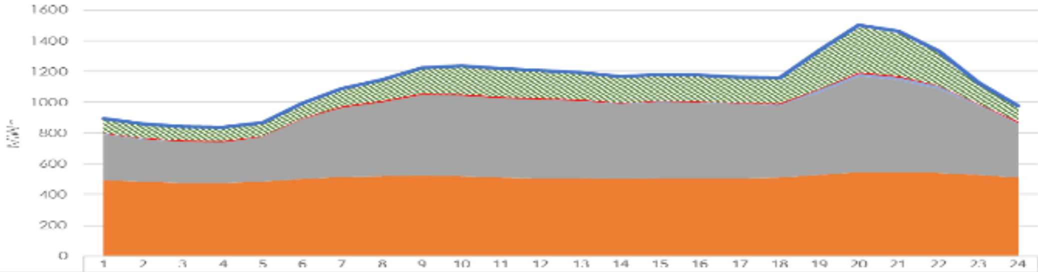
5.3 DAILY GENERATION WITH SEVEN FORKS SOLAR PROJECT

The annual average hourly load and generation profile for Kenya in Figure 7 shows that geothermal generation acts as the country's primary baseload power resource with hydroelectricresources providing intermediate power. The system starts peaking after 6pm and reaches maximum demand around 8pm.

Solar power is an intermittent resource producing energy only during sun hours. The bottom part of Figure 7 shows that the Seven Forks Solar Project starts producing at 6am, reaches peak production around 1pm, and stops producing at 6pm in the evening. The estimated average dailygeneration of the Seven Forks Project is 267 MWh. Given that solar has a lower marginal cost thanHFO/Diesel, it would be less costly to dispatch the solar plant before the HFO/Diesel plants, or alternatively to reduce the hydroelectric generation (to save water) while the solar plant is generating and release the stored water to generate more hydro during the peak hours thereby displacing HFO/Diesel generation. The effect of water storage is increased as the hydroelectric facilities run in a cascade of five plants. A come of water stored in Masinga (the most upstream station) would generate in Masinga and then Kamburu, Gitaru, Kindaruma and finally Kiambere (the most downstream station). As solar and wind generation increases in Kenya, flexible operationof hydroelectric facilities will be crucial in supporting intermittent output from these facilities.

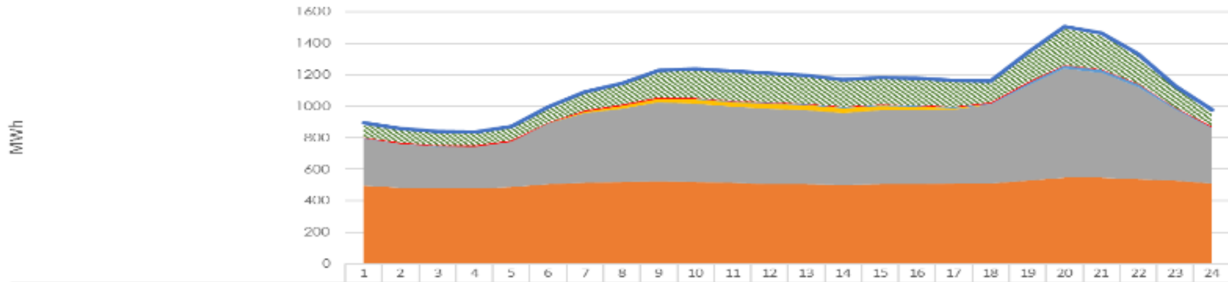
The net effect of both approaches will be the same as HFO/Diesel generation will be displaced bythe amount of solar generation. The information presented in Figure 7 assumes that water will be stored while solar is generating and then released to displace HFO/Diesel during peak hours. Based on this analysis, approximately **267 MWh** of HFO/Diesel generation would be displaced dailyand approximately **97.62 GWh** of Diesel/HFO generation would be displaced annually.

Figure 7: Average Annual Hourly Load Without and With Solar



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Daily HFO/Diesel Generation	94	90	88	88	89	96	116	136	169	182	182	180	175	167	166	165	162	165	244	296	281	214	133	102
Wind	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Imports	3	2	2	2	1	1	0	1	1	2	2	3	4	6	4	4	4	6	15	18	19	16	6	4
Hydro	298	276	266	264	287	388	451	483	526	527	515	509	502	484	496	491	480	467	535	628	600	550	453	352
Geothermal	495	483	478	477	487	504	516	520	522	518	512	507	505	503	505	506	508	511	528	544	544	539	528	511
Annual Average Hourly Load	896	858	841	837	870	995	1090	1147	1227	1238	1221	1209	1196	1170	1181	1176	1165	1160	1340	1505	1463	1334	1129	976

Hours



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
HFO/Diesel (capacity reduced during peak)	94	90	88	88	89	96	116	136	169	182	182	180	175	167	166	165	162	132	178	229	214	181	133	102
Wind	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Imports	3	2	2	2	1	1	0	1	1	2	2	3	4	6	4	4	4	6	15	18	19	16	6	4
Seven Forks Solar	0	0	0	0	0	0	9	19	24	29	31	33	32	30	26	22	11	0	0	0	0	0	0	0
Hydro (saved cap. Added during peak)	298	276	266	264	287	387	442	463	502	498	483	477	470	454	470	468	469	500	602	694	667	583	453	352
Geothermal	495	483	478	477	487	504	516	520	522	518	512	507	505	503	505	506	508	511	528	544	544	539	528	511
Annual Average Hourly Load	896	858	841	837	870	995	1090	1147	1227	1238	1221	1209	1196	1170	1181	1176	1165	1160	1340	1505	1463	1334	1129	976

Hours

Source: based on Ken-Gen study.

▶ Avoided Emissions

Avoided emission for CO2, NOX, SOX, and CO were calculated by multiplying the heat rate for diesel generators (assumed to be 8000 Btu/KWh) by the emission factors[33] for diesel fuel. The results are summarized in Table 5.

Table 5: Avoided Emissions

DESCRIPTION	EMISSION FACTORS (KG/MMBTU)	HEAT RATE35 (BTU/KWH)	YEARLY GENERATION DISPLACED (GWH)	AMOUNT (METRIC TONS)
CO_2 avoided	73.32	8,000	97.62	57,257
NOX avoided	2.00	8,000	97.62	1,565
SOX avoided	0.13	8,000	97.62	103
CO avoided	0.43	8,000	97.62	337

Source: based on Ken-Gen study.

5.4 JOB OPPORTUNITIES AND HUMAN CAPACITY BUILDING

Another important aspect of the project is its impact on employment in Kenya. This Project would create i) temporary jobs during construction and ii) permanent full-time jobs during operation. Solar PV projects of this size create a significant number of jobs during the construction phase. Althoughpermanent job creation associated with the operation phase is lower than that for conventional generation technologies, there is potential for indirect yet associated business growth (with less reliance on foreign labour) as solar generation becomes a larger part of Kenya's generation portfolio. Such business areas should include operation and maintenance services, spare parts supply, panel cleaning, vegetation management, data acquisition and monitoring systems, and security.

5.5 JOB CREATION

It was estimated the total number of labour hours for the Seven Forks using labour hours estimates published by the U.S. National Renewable Energy Laboratory (NREL).[36] The results of the calculation are presented in Table 6 below.

Table 6: Calculation of Total Labour Hours for Seven Forks Solar Project

DESCRIPTION	LOW CASE	BASE CASE	HIGH CASE
Skilled Labour Content Hrs/KWdc	0.633	0.844	1.055
Total Skilled Labour	30,086	40,115	50,144
General Labour Content Hrs/KWdc	0.139	0.185	0.231
Total General Labour	6,607	8,793	10,979
Total Labour Hours	36,693	48,908	61,124
Contingency for lost labour hours (25%)	9,173	12,227	15,281
Total Labour Hours Incl. Contingency	45,866	61,135	76,404
Hours Worked Daily	8	8	8
Total Construction Days	200	200	200
Total Full Time Employment Generated	29	38	48

Source: based on Ken-Gen study.

It should be noted that the above numbers are estimates for the U.S. market and represent an average employment number during construction. A contingency component was included to reflect a potential productivity variance from U.S. rates. Actual employment during project construction would fluctuate depending on the labour intensity of the tasks performed e.g. the project would employ more people during the civil construction phase which is more labour intensive and less people during the electrical and instrumentation phase of the project. Based on new studies, it is expected around 200 people to be employed during civil construction phase of the project.

based on previous experience, Solar PV plants require very few full-time employees for operation and maintenance. Since this assumption, expected total full-time employment for this project is shown in table 7:

Table 7: Full-time Employment during Operations

DESCRIPTION	QUANTITY
Plant Operator	1
General Maintenance	1
Security and Administration	3
TOTAL OPERATION JOBS	**5**

Source: based on Ken-Gen study.

5.6 HUMAN CAPACITY BUILDING AND TECHNOLOGY TRANSFER

Since this is KenGen's first solar project, there will be considerable opportunity for the developmentof capabilities and experience in solar PV technology. The confidence gained through successfulexecution this project would encourage increased investment in Kenya and the region.

6 TECHNICAL ANALYSIS AND ALTERNATIVES

6.1 EQUIPMENT ASSESMENT

There are many different options when it comes to available solar equipment to be used on solarprojects. The selection of proper equipment is based on the following:

- Technical prefeasibility
- Capital cost
- Energy production
- Maintenance cost
- Reliability
- Availability

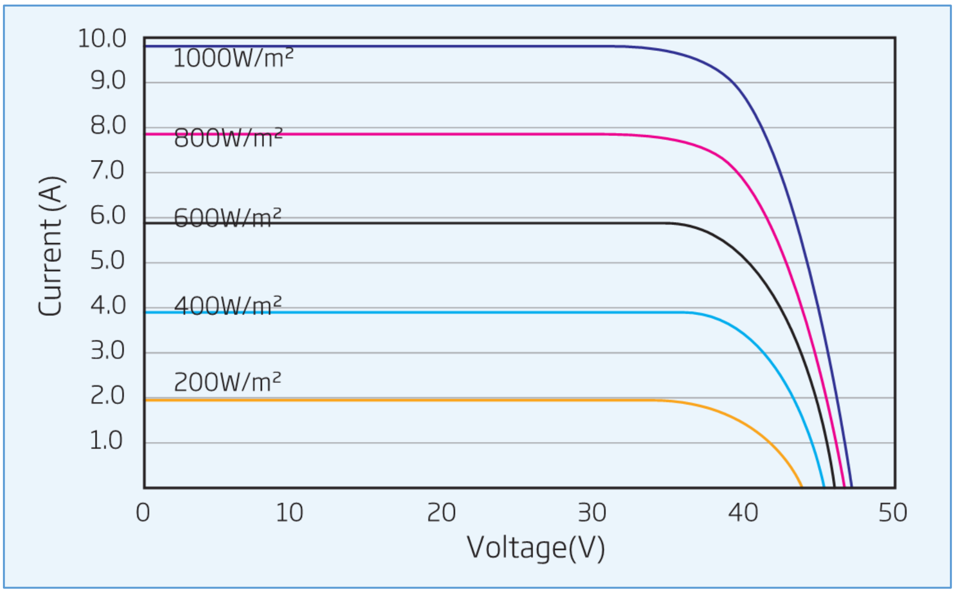
These factors were reviewed for the three main pieces of equipment: PV modules, inverters, and racking system. If the equipment was technically feasible for the Site, a LCOE calculation was performed considering the other factors for different combinations to determine the lowest cost of energy solution.

Several typical designs with varying equipment were created and modelled at a high level with the solar resource data to provide guidance as to which parameters, typically tilt and row spacing, were likely to lead to more optimized energy output for a particular equipment choice. Once the most promising equipment types were identified, a range of parameters was modelled to calculate a comparative LCOE for those designs.

Solar PV Modules

Solar Photovoltaics (PV) are semiconductor devices that convert solar energy into DC electricity. The amount of direct current that can be produced by the PV modules depends on the electricalcharacteristics of the module, the irradiance density that is incident to the solar cells, and the temperature of the cells. At the Project Site, the GHI can reach up to approximately 1400 W/m2 depending on the time of the year, time of day and cloud coverage. The current output is then determined by the I-V curve of the module[13]. Figure Curve below shows the curves for the TrinaTSM-DE14A(II) 72-cell module, which is a Tier 1 mono-crystalline module, and was used for the preliminary energy estimates for the appraisal.

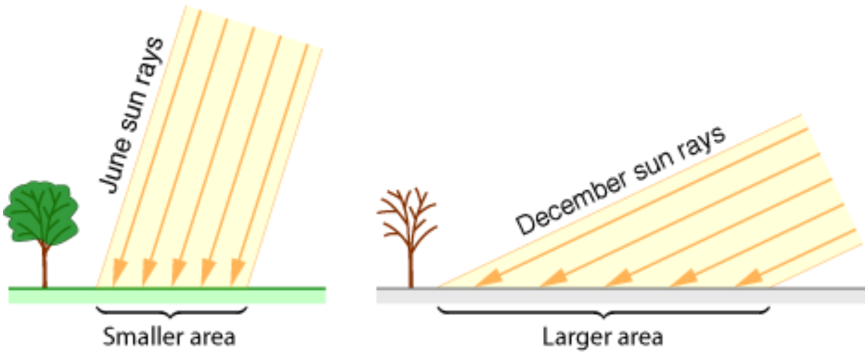
Figure 8: Voltage and Current by Tilt factor



Source: based on Ken-Gen study.

The tilt angle of the panels from horizontal, the azimuth angle from due south and the amount thatthe modules are shaded (solar access) also determine the amount of direct irradiance on the modules. The more direct irradiance, the higher the amount of energy will hit the panel, which increases the power output. This is the advantage of single-axis trackers following the sun's path over a fixed-tilt racking system, particularly at the equator. The path of the sun traverses directly overhead, at least 70 degrees above the horizon at noon. The lower sun angles spread the irradiance over a larger area of PV module, and therefore results in a lower watt per square meter. This is illustrated below where the energy passing through the same surface area perpendicular to the sun radiation is spread over a larger area when the sun angle is lower.

Figure 9: Equatorial sun angle will be similar to June for the entire year



Source: based on Ken-Gen study.

At the Project site, the tracker advantage is an annual gain of almost 20% compared to the horizontal irradiance, while the fixed tilt actually has a drop of approximately 1% compared to horizontal irradiance. This is the key advantage driving the recommendation of single-axis trackers.

The PV modules are typically connected together in a series configuration until the maximum voltage of the series of modules (source circuit) reaches the maximum DC voltage allowed. PV modules are made up of many individual cells that all produce a small amount of current and voltage. These individual cells are connected in series to produce a larger voltage. PV panels areoverly sensitive to shading. When shade falls on a panel, the shaded portion of the panel cannot collect the high-energy beam radiation from the sun. If an individual cell is shaded, it will act as aresistance to the whole series circuit, impeding current flow and dissipating power rather than producing it. By determining solar access—the unimpeded ability of sunlight to reach a solar collector—one can determine whether an area is appropriate for solar panels.

The source circuits may be combined at a DC combiner box with a fuse to protect each source circuit and connected to a central type inverter, or connected directly to string inverters which combine the strings and output at AC. The PV inverter has two main functions; adjust the DC voltage to maximize the power delivered and convert the direct current to alternating current. The process of maximizing the power output is called maximum power point tracking (MPPT). Thereis typically only a single MPPT on each inverter, so in addition to the cell resistance issue, each module should be at the same angle and have the same solar access (no shading) as the other modules or the efficiency of the system will be decreased. This does not apply to modules with micro inverters or DC optimizers which can adjust for different irradiance on each module.

Module Technology Review

The wealth of different PV technologies that exist today can be divided into two main categories: crystalline silicon technologies and thin-film technologies. Today, crystalline silicon modules make up the vast majority of PV installations. In the last decade, these technologies have matured and achieved considerable cost advantages in relation to thin-film modules. Asia, especially China, has the largest market share in production of crystalline silicon modules, as large European and American module manufacturers have difficulty competing with the low price offered by the Asian producers.

The main advantages of thin film solar cells are their diffuse irradiation efficiency in comparison toc-Si, reduced losses from shading, their relatively low consumption of raw materials, high automation and high production yield ensuring relatively low production cost, ease of building integration, good performance at high ambient temperature, and reduced sensitivity to overheating. The drawbacks are lower efficiency, higher cost and the industry's limited experience with lifetime performance. Thin film technologies will require more area than crystalline silicon technologies in order to reach the same capacity due to their lower efficiency. Thus, area availability and land cost may present limitations on the use of thin film technologies. However, First Solar, the largest thin-film manufacturer has made great strides in increasing their efficiency near to the efficiency of c-Si PV modules.

Comparison matrix

PV module technologies are qualitatively evaluated on the six key performance indicators: cost; efficiency; temperature characteristics; lifetime; environmental impact; and maturity. Cost is the module cost of the technology per Watt-peak, the output under Standard Test Conditions (STC). The module cost has a strong impact on the LCOE of a project. For crystalline silicon technologies, the cost of the module is currently about \$0.35-\$0.45 per Watt. First Solar thin-film modules are approximately the same price but require an additional \$0.06 per Watt to install relative to c-Si modules.

Table 8: Comparison of key performance indicators for various PV technologies

TECHNOLOGY	COST	EFFICIENCY	TEMPERATURE CHARACTERISTICS	LIFETIME	ENVIRONMENTAL CONSIDERATION	MATURITY
pc-Si	+	±	±	±	+	+
mc-Si	+	+	-	±	+	+
CIS	+	-	+	±	±	±
CdTe	+	-	+	±	-	+
a-Si:H	+	-	+	±	+	-

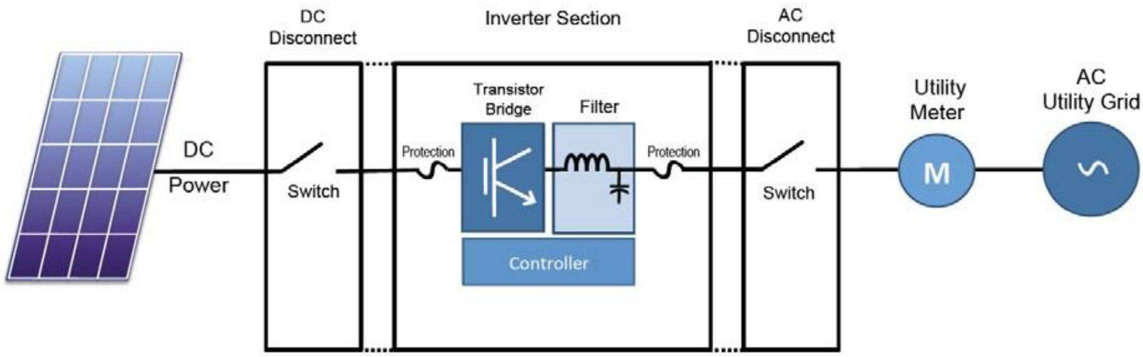
Source: based on Ken-Gen study.

Inverters

The wealth of different inverter technologies that exist today can be divided into three main categories: micro-inverters (typically one or two per module), string inverters (10-120kW), and central inverters (500kW+).

In general, the inverter is the component of the PV system that converts the DC electricity produced by the PV array into AC electricity for the utility grid. This is illustrated in the high-level inverter diagram below.

Figure 10: High Level Inverter Diagram



Source: based on Ken-Gen study.

The key components of a PV inverter are as follows:

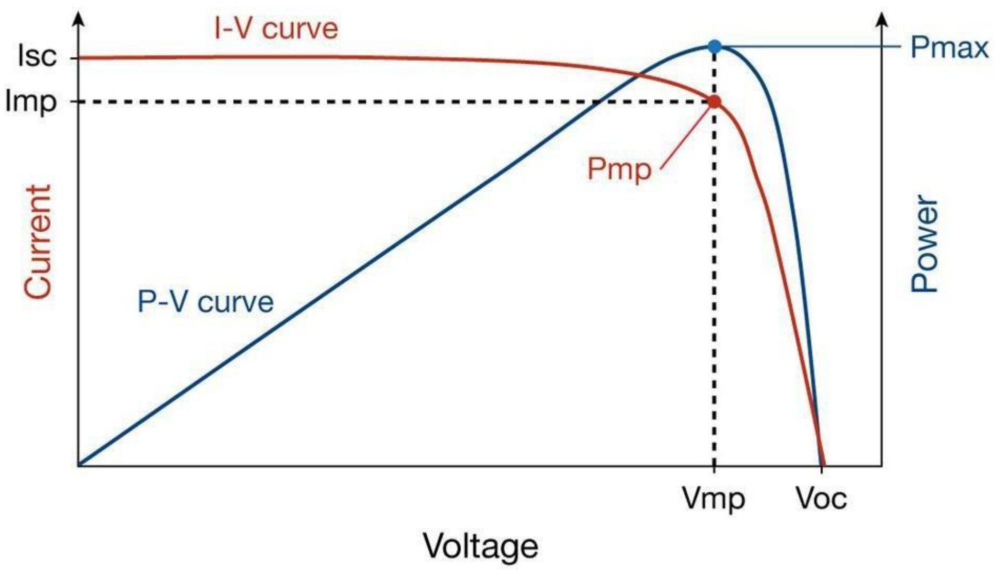
- **DC Input Section** – accepts input from PV array and typically includes a disconnect switch and fuses or a circuit breaker for protection.
- **Power Electronic Converter** – transistor based switching devices that convert the DC input to AC output.
- **Filter** – Inductive and capacitive components that smooth the output of the converter to provide high power quality to the utility grid.
- **Controller** – A microprocessor based board (or boards) that implements all inverter control functions and communications with other equipment in the system.
- **AC Output Section** – provides output connection to utility grid and includes a disconnect switch and fuses or a circuit breaker for protection.
- **Enclosure** – Provides environmental protection for the PV inverter's electronic components.
- **Display** – A control panel that allows for viewing of the PV inverter operation and setting of operational parameters. This is common on larger PV inverters. On smaller inverters this may be implemented through a communication system that is accessed by a computer.

- **Transformer** – Often included or required to be installed between the inverter and the utility grid to match the inverter output and utility grid voltages and provide electrical isolation (note that this is not shown in the block diagram above).

The key PV functions performed by a PV inverter are related to the control of the input DC powerfrom the PV array and output AC power to the utility grid. Additionally, features to provide systemprotection and data communications are typically included in a PV inverter.

The control of the input DC power by a PV inverter includes starting up the PV inverter when sufficient power is available from the PV array, drawing the maximum amount of power from the PV array during normal operation, and stopping the inverter at night. A key element of this control is the Maximum Power Point Tracking (MPPT) algorithm. This is typically implemented in thecontroller software. The MPPT algorithm controls the power electronics converter to draw DC current from the PV array at the maximum power voltage which will maximize the power generation. This is illustrated below.

Figure 11: Maximum Power Point Operation



Source: based on Ken-Gen study.

Reliability is an important criterion in selecting a PV inverter. Historically, inverter issues have been the largest contributor to lost availability from a PV system. Evaluating the reliability of a PV inverter involves communication with the manufacturer and reviewing historical information. Many PV inverter manufacturers obtain a technology review report from a third party that includes commentary about the product reliability. It is generally best to select a mature product from a well-established PV inverter manufacturer.

Inverters, whether reviewed by a third party or not, still have the most parts and can have issues over the life of the plant. Whereas PV modules showcase power warranties of 25 years, inverters traditionally have had five-year warranties, with ten-year warranties only recently becoming standard. In a relatively short period of time, inverters have come a long way from providing inversion and basic power point tracking and are now seen as components that enhance systemoperation, increase design flexibility and augment system reliability. New technology trends go beyond mere efficiency and reliability gains, and there is real potential to extend the functionality of PV systems beyond just system generators.

Racking Systems

Fixed-tilt racking systems are typically the lowest cost alternative and can scale to very large utility- sized systems. These systems are best when the land available is more than enough to meet energy needs and there is a serious concern for the operation and maintenance of the PV systems. Fixedsystems may be used when the solar resource available is relatively low, such that a tracker would not harvest enough extra irradiance to justify the additional cost. Nearly all ground-mounted systems have a foundation with metal posts which are either placed in the ground or into a ballastsystem. Ballasted foundations are not common and only used when the ground is unusable for driven pile foundations.

Fixed-tilt systems may have the modules arranged in various ways based on optimizing energy output and cost of racking structure. The modules can be placed in landscape or portrait and stacked as many as six-high in landscape or three in portrait. One of the drawbacks of fixed-tilt systems is that the modules will become shaded in the evening and afternoon hours, which can greatly reduce their output during those times.

Fixed-tilt systems cost about $0.08 per Watt to install for utility systems and an O&M contract is approximately $15/kW/yr. The PROs of this technology are:

- Lower installed cost

- Less land required
- Less maintenance cost
- No moving machinery to maintain
- Highly scalable CONs:
- Less energy yield (kWh/kWp) relative to trackers
- No backtracking

Figure 12: Example of Ground-Mounted System

Source: based on Ken-Gen study.

The typical power density of a ground-mounted system is 4-5 acres per MWdc for fixed-tilt and 5-6acres per MWdc for single-axis trackers. This depends on the module power density and the Ground Coverage Ratio (GCR). The GCR will be set in order to maximize the direct solar irradiance while minimizing the row-to-row shading and wind forces. The GCR of a typical fixed-tilt system is around 0.50 to 0.60, which means at least half of the land is covered with PV modules. The GCR of a typical tracker is 0.30 to 0.45 depending on the size of the tracker. This means that for a given amount of land, far more modules can be installed on a fixed-tilt system, but it will not have the increased energy yield provided by a tracker system.

Tracking System

Tracking systems are PV racking systems that will rotate with the angle of the sun in order to increase the amount of direct irradiance hitting the PV module. Because direct irradiance produces a relatively high amount of energy in comparison to diffuse irradiance, the tracking systems can produce up to 40% more energy. Tracking systems have been installed on utility-scalePV projects for over 10 years. While not as simple as the fixed-tilt systems, the tracker manufacturers have been innovating over the last 10 years to make them closer to the cost and maintenance required for fixed-tilt systems.

Tracker systems are comprised of a PV module rack, which is then connected to a torque tube. The torque tube is rotated by a motor either directly connected to the torque tube (self-poweredtrackers) or by a torque arm that connects up to 30 tracker rows to a single motor. The motors for the multi-row trackers (e.g., ATI) are typically powered by AC low voltage cabling from the low- side of the MV transformer at the Power Conversion Station. The tracker rows with a motor included, are typically powered by a separate solar module dedicated to the motor (e.g., NEXTracker Horizon) or by using the power from the modules on the tracker row (e.g., Soltec).

The self-powered tracker design with a single motor per row is becoming more prevalent becausethey allow free access between rows (the multi-row trackers are impeded by the torque arm), are more flexible for designs since they are not linked to the other rows, do not require AC cable and are typically less expensive.

Trackers utilize a strategy called "backtracking" that will tilt away from the sun during the morningand evening hours to eliminate shading from adjacent rows. Partial shading of a c-Si module cansignificantly reduce the output of the module. Backtracking allows the trackers to eliminate shading with the penalty of reducing the direct irradiance.

Transformers

The medium voltage step-up transformers at the Power Conversion Station (PCS), which contains the inverters, transformer, MV switchgear and auxiliary equipment, steps up the voltage of the inverter AC output to the MV collection voltage of (4.6kv - 34.5 kV). These transformers are arranged in either a single low-side winding or double low-side winding. The double low-side configuration is used when combining two inverters to the same transformer, which need to be mechanically isolated on the AC side. The transformers are sized to accommodate the expectedoutput of the inverter and are generally 1 – 4 MVA in size. The transformers will have a single outputand switch on the high side, which will then connect into the MV switchgear at the PCS. The transformers are filled with either mineral oil or a less flammable FR3 oil. The FR3 oil is recommended, since it is much better for the environment in the case of a leak.

▶ Switchgear

Each of the PCS locations will contain a MV switchgear panel. This panel performs a few functions;combines the output of the transformer and the previous PCS MV switchgear output, provides a disconnecting means at medium voltage level, and grounds the circuits for safe services of the transformer. The switchgear is rated for the MV collection voltage as well as the interrupting rating required on the site.

▶ Meters

There are typically only meters at or near the point of interconnection. There are also metering devices at the inverters that allow the input and output of the inverters to be collected and communicated using the project communications system. The meters at the point of interconnection must be high-accuracy, utility-grade revenue meters. These meters can either be bidirectional to both record the output during generation and input when not operating, or two unidirectional meters, one to record the incoming energy and the other to record the outgoing.

▶ Balance of System

DC cables are comprised of the source circuits and the output circuits. The source circuits, or strings, connect the modules in series until the maximum rating of the cable insulation is reached(1500Vdc). The amount of current on the source circuit does not increase as modules areconnected because they are connected in series. Harnesses are also widely used, which combine2 or more source circuits together to more efficiently use DC cable and combiner box inputs. The cable is rated for sunlight exposure, PV installations, and direct burial.

The output circuits, or DC feeders, are the output of the combiner box and are a much larger sizedcable than the source circuits. Since the combiner box combines in parallel, the voltage is not increased with connecting multiple source circuits. However, the current will increase with each source circuit that is connected, which requires an increase in capacity and size. The cable is alsorated for 1500Vdc and is rated for direct burial. The output circuits are typically routed together ina large trench back to the inverters in conduit or directly buried. The thermal heating of those cables must be modelled to ensure that the cables do not overheat.

Foundations

There are many different types of foundations that may be utilized on ground-mount projects. Thisincludes; driven piles, helical piles, concrete encased piles, earth screw piles, and ballasted. The most common foundation type is driven piles. These piles can typically be used in many different soil types. Helical piles are often used when the ground is very hard and the driven piles are not able to reach depth without failure, or when there is poor soil cohesion, as strong pull-out resistanceis provided by a disc held in place by the column of soil above it. Concrete encased piles may beused when corrosion is a large issue. Ballasted foundations may be required on land such as landfillswhere required friction of a driven pile is not achievable or in very hard soils/rock. Ballasted and concrete foundations are often the costliest and the least common for ground-mount systemsalthough recent cost reducing methods have brought them closer to other foundation alternatives.

Although the geotechnical report provides a preliminary recommendation of earth screw piles, the Consultant does not recommend ruling out any of the foundation options referenced above.The reason is that the soil characteristics, particularly borderline soil cohesion at relevant depths, do not clearly support one alternative to the exclusion of the others, particularly in a market like Kenya where few grid-scale solar plants have been constructed. Soil treatment (or other reinforcement measures), such as removal, backfilling with proper backfill material, and compaction may be required to improve soil properties. Each of the potential options will need to be evaluated from the technical, cost, and schedule perspective by the prospective EPC contractors at the EPC bidding stage. The candidate contractors should be allowed to perform additional geotechnical investigations at the bidding stage, if they deem appropriate to do so, and to select the solution they determine to be optimal for the design and construction methods they propose.

The foundations are also required to be high enough above grade to allow the 50-yr or 100-yr flooddepth to be lower than the PV modules. Typically, the lowest point of the PV modules is 0.3m abovethe flood depth.

6.2 DESIGN ASSUMPTIONS

The Site was optimized in order to utilize the available space in the most efficient way. This included researching and modelling multiple design options considering the relevant variables and deducing a short list of preferred alternatives based on experience and other factors. Below is a summary of the optimization of the plant and the design variables.

▶ Fixed vs. Tracker

Tracking systems are PV racking systems that rotate with the angle of the sun to increase the amount of direct irradiance hitting the PV module. Because direct irradiance produces a relatively high amount of energy in comparison to diffuse irradiance, the tracking systems can produce up to 40% more energy. However, these tracking systems do come at a premium cost over fixed-tilt systems which do not require any motors. Also, to realize the true benefit of a tracking system, the distance between the tracker rows must be greater than that for fixed-tilt systems, which requires more land to install an equivalent amount of plant capacity. For this Project, the Site is land constrained, so the DC system capacity is lower for a tracking system than a fixed system.

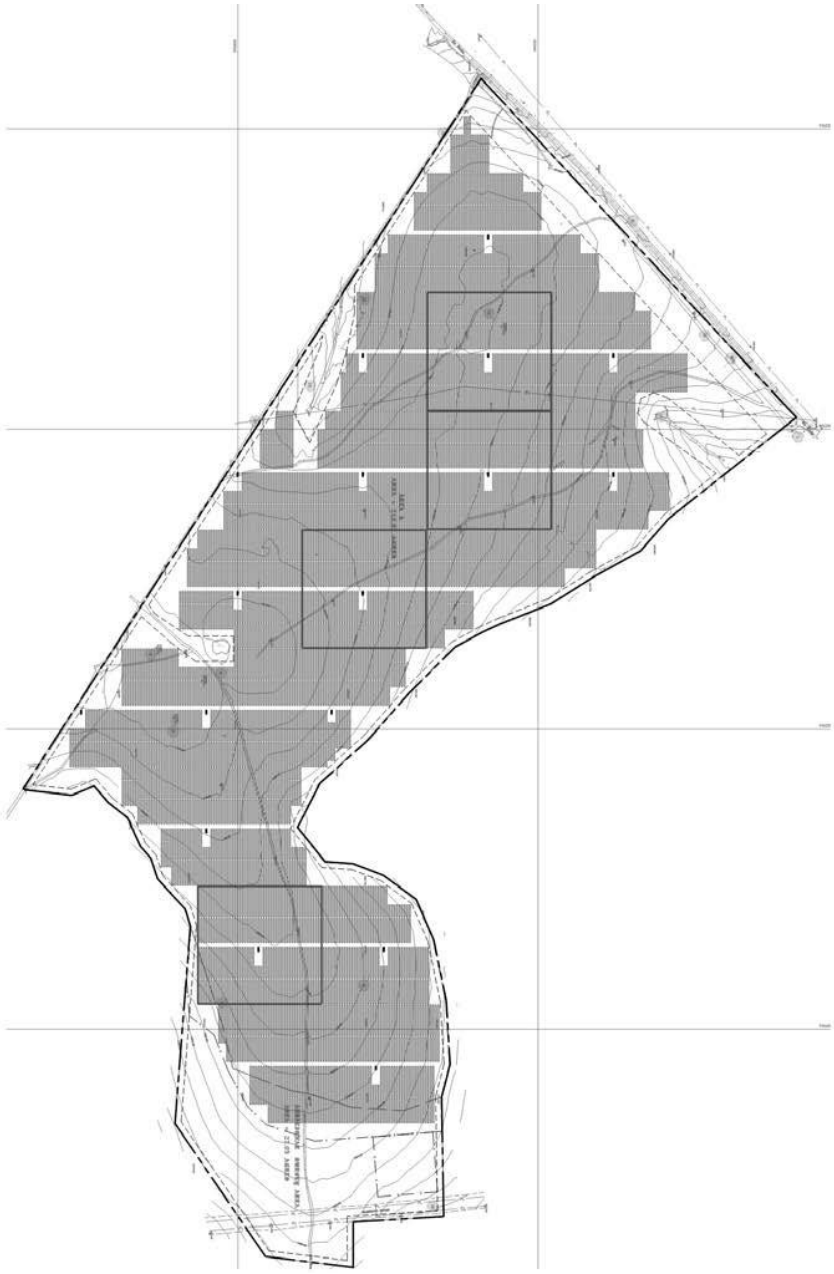
Because of the inherent differences in the two racking systems, a comparative LCOE analysis wasperformed to find the lowest LCOE between fixed-tilt and tracking. This was completed for multipleGCRs (i.e. the length of the PV panel over the distance from row-to-row, which is roughly the ratioof the ground covered by panels), each of which provided a different MWdc based on the available land. The amount of fixed and tracking systems that could fit on the Site was found by laying out both systems as can be seen below. The parameters of these systems are based on the maximum GCRs (lowest row spacing) for both fixed-tilt (0.55) andtracker (0.45) that are typically used in the industry. The fixed-tilt maximum GCR of 0.55 allows for enough space between rows to drive through, whereas the maximum tracker

GCR of 0.45 is whereyou typically see lower gains in energy because of increased back-tracking.

Figure 13 - Fixed-Tilt Conceptual Layout

Source: based on Ken-Gen study.

Figure 14 - Tracker Conceptual Layout



Source: based on Ken-Gen study.

For these two layouts, it was found that the fixed-tilt system can fit 57.66 MWdc and the tracker system can fit 47.53 MWdc. Both systems assumed (17) 2.5 MWac inverters (42.5 MWac total), whichallows for at least 40 MWac at the point of interconnection, the requested system size. Once the available system size for both types of systems was established, the different GCRs and DC/AC ratios were evaluated and modelled. With the trackers, the GCR was studied at values lower than that associated with maximum site DC capacity. GCRs higher than 45% were excluded because of their negative impact on LCOE. For fixed-tilt, the MWdc was lowered from the maximum, because it was determined that DC/AC ratios higher than 1.36 had a negative impact on LCOE, due to the available DC energy being limited by the AC capacity. Higher DC/AC ratios can be economically viable in locations with lower solar resource, but in a higher solar resource location, too much energy is wasted by oversizing. Using the conceptual layouts and the estimated costs of a fixed-tilt system and trackingsystem, below shows that at this location tracking systems are more advantageous thanfixed-tilt in terms of LCOE. It also shows that the tracking system with 45% GCR has the highest energy output with only a slight increase to LCOE versus lower GCRs. Although tracking can result in increases of unavailability due to potential mechanical failures of the motor system, the possibility of such failures should not impact the decision to use single-axis tracking because:

- Failures will only effect small portions of a PV plant
- Sound O&M practices should mitigate excessive failures materially impacting availability, and

Based on these findings, the tracking system with a 45% GCR was chosen as the basis for this Study.The tracker type that is recommended would have individual motors for each row. In the event ofa motor failure, this will allow the manufacturer to send a new motor, and only a small portion of the plant will be impacted. This will also allow for variable row spacings based on the slope of theSite to maximize efficiency. The tracker system assumed for this design is the NEXTracker Horizon system with self-powered motors and independent rows. This negates the need for AC cable to the motors, allows free access between rows, and has been installed throughout the world. Thereare, however, other tracker manufacturers that can be used and a manufacturer with a local presence should be a priority on this Project, which may include ATI, Convert Italia, Arctech, Soltecand Clavijo.

Table 9: Fixed vs. Tracker Optimization

TRACKER (GCR – 45)		TRACKER (GCR – 44)	FIXED DCAC 1.36	FIXED DCAC1.21	FIXED DCAC1.15	TRACKER-FLAT
MWdc	47.53	46.41	57.66	57.66	57.66	47.53
MWac	42.5	42.5	42.5	47.5	50	42.5
DCAC Ratio	1.12	1.09	1.36	1.21	1.15	1.12
GHI	2157	2157	2157	2157	2157	2157
POA	2621	2625	2121	2121	2121	2157
MWh	97,143	95,033	94,225	95,376	95,504	79,767
Yield	2044	2047	1634	1654	1656	1678
PR	0.780	0.780	0.770	0.780	0.781	0.778
AC Capacity	26.1%	25.5%	25.3%	22.9%	21.8%	21.4%
DC Capacity	23.3%	23.4%	18.7%	18.9%	18.9%	19.2%
CAPEX $ / kW	$1,170	$1,170	$1,060	$1,070	$1,070	$1,170
OPEX $ / kW	$19	$19	$15	$15	$15	$15
LCOE $ / MWh	$55.90	$55.80	$61.90	$61.70	$61.60	$65.70

Source: based on Ken-Gen study.

DC/AC Ratio

The DC/AC Ratio, which is sometimes called the Inverter Loading Ratio, also has a large impact on the amount of energy that can be produced by a PV system. The DC/AC ratio is simply the ratio of the MWdc over the MWac. A higher DC/AC ratio will allow for more energy during the morning and evening (shoulder hours), because the inverter will be operating at a higher output but less than the maximum. During the high-irradiance hours of the day, the inverter will "clip" thecurrent of the modules by increasing the DC voltage. This allows the inverter to continue to operate even when the amount of energy that could be produced by the modules is much higher than the capacity of the inverter. The downside of a high DC/AC ratio is that the yield (kWh/kWp) will decrease since the inverter is clipping the energy from the modules more often. This will typically increase the cost on a LCOE basis as well, even though more energy will be produced. Fixed-tilt systems are at a disadvantage to tracker systems in respect to energy yield per Watt, particularly when fixed project costs are considered, and a larger DC/AC ratio is typically necessary to decrease the LCOE of the system to get costs closer to tracking systems. However, in the high solarresource case at Seven Forks, the higher DC/AC ratio is not advantageous, as too much energy iswasted by the AC capacity limit. The ability to have the fixed-tilt rows closer (higher GCR) allows the Site to fit additional DC capacity, which also increases the DC/AC ratio for a given plant output capacity.

The DC/AC ratio of the plant design selected for the project was set at 1.12. This ratio was establishedby maximizing the amount of tracking modules that could be installed on the Site while maintaining the highest AC capacity (42.5MW) and a maximum GCR of 45%.

PV Module Types

Crystalline silicon and thin-film modules are the two most-installed module types and are the two types that were considered for this Project. Poly-crystalline modules have historically been installed more frequently than mono-crystalline due to the former's lower installed cost, but to achieve higher efficiencies manufacturers have transitioned to mono-crystalline over the past few years for standard utility-scale projects. The costs of mono-crystalline modules have nearly reached parity with poly-crystalline on a $ per Watt basis at the efficiencies assumed for this design. An EPC bidding with poly-crystalline modules may be able to quote a lower $ per Watt, but they would not be able to put as many Watts on the site, because they would be using lower efficiency modules.

As mentioned earlier, thin-film modules have about a $0.06 per Watt installation cost premium overthe crystalline modules because they are much smaller and do not have a metal frame, so more installations with specialized clips are required. Thin-film modules do produce more energy in high- humidity areas because of its increased capacity to converter diffuse irradiance as compared toc-Si modules. However, it was found that the Project location did not lend itself to a large enoughincrease in energy to overcome the additional cost of the modules because the spectral adjustment to the solar resource did not increase the specific solar energy available to the First Solar technology compared to mono crystalline.

Based on the information provided above, mono-crystalline silicon was selected as the most suitable module technology for producing the lowest Project LCOE. These modules come in various sizes based on the number of cells. Utility projects typically employ 72-cell modules. Trina Solar 72-cell Trina TSM-DE14A(II) 340W modules were used for the design in this Study, because they are a top tier supplier and have been extremely competitive in price. However, it is important to note that many different modules could be used on this Project, including thin-film and such alternatives should not be discarded until the time that firm equipment or EPC price quotes are received andevaluated.

Inverter Technologies

The three main inverter types were considered for the Project. Micro inverters are not cost effectivefor large utility projects such as Seven Forks Solar. They also require a large amount of data collection and cabling. String inverters are becoming more prevalent on large utility projects thanks to reduced inverter costs as low as $0.08 per Watt. Central inverters, however, still make upthe vast majority of utility-scale inverters installed globally with prices as low as $0.07 per Watt. Theargument for string vs. central has recently centred around operation and maintenance costs. On one hand, you have many more string inverters (20-30x more than central) that could fail, butthese inverters are much easier to replace than a central inverter if they were to fail. If one string inverter fails, it only takes down a small portion of the plant, whereas the central inverter can take down a large portion of the plant for long periods of time while waiting for parts and technicians. At this point, however, string inverters that are able to perform the requirements of utility-scale projects (as discussed in Section 9.3) do not have comparable experience and maturity of installations as central inverters do and are not recommended for a site of this size.

Based on the technical analysis, the systems proposed for this project are large utility-scale central inverters. The main differences between these inverters are the power capacity and the rated DC voltage. The DC voltage options are 1000Vdc and 1500Vdc. 1000Vdc have been installed for approximately 8 years, and the 1500Vdc for approximately 3 years. The 1500Vdc, however, allows you to purchase a 2.5 MWac inverter at a small increase in price for the same inverter rated at 1000Vdc that can only output about 2.0 MWac. This is because the inverter ratings heavily rely on the amount of DC current they are converting, and raising the voltage allows the same current with a larger power output. Movingto 1500Vdc also allows about 33% more modules to be connected in series, which greatly reducesthe amount of DC cable required for the Project.

6.3 CAPITAL COSTS AND OPERATING EXPENSES

The CAPEX and OPEX estimates provided in this report are based on publicly available cost data for major equipment, recent market trends, and expert judgement. The estimates provided in this report should be used for the purposes of the feasibilitystudy only. The costs and breakdowns associated with bids from EPC contractors will vary from the estimates provided in this report.

6.3.1 Capital Cost Estimate

Project CAPEX is divided into the following seven main categories:

- Modules and Inverters
- Balance of System—Structural
- Balance of System—Electrical
- Civil Works
- Labour
- Soft Costs
- Contingency, Spares and Margins

The actual components will be based on the winning EPC bid, which will reflect the most attractive balance of cost and performance of the equipment in the EPC proposal.

Equipment and material supply for the Project is estimated at US$38.6 million and services areestimated at US$8.4 million. A breakdown of these estimates is provided in below.

Table 10: Capital Cost Estimate

TYPE	DESCRIPTION	UNIT	UNIT PRICE (US$)	QTY	TOTAL (US$)
Modules and Inverters					
Modules	Trina TSM-DE14A(II) 340W	Each	119	139,800	16,636,200
Inverters	SMA Sunny Central 2500-EV 2500kW w/integrated transformer	Each	200,000	17	3,400,000
Total Modules and Inverters					20,036,200
Balance of System—Structural					
Racking	90-module NEXTracker Horizon Rows	Each	3,000	1,376	4,128,000
	60-module NEXTracker Horizon Rows	Each	2,200	266	585,200
Foundation	Earth Screw Foundations	Each	120	17,500	2,100,000
Total Balance of System—Structural					6,813,200
DC Cable and Source Circuits, Combiner Boxes	6 mm2 CU, PVF-1, 1500 VDC, UV Resistant	300 m Spool	150	1,700	255,000
	4 mm2 CU, THWN	300 m Spool	100	850	85,000
	300 mm2 AL, 90C, 1500 VDC Direct Burial	50 m spool	800	1,000	800,000
	Combiner Boxes	Each	3,000	272	816,000
Medium Voltage Cables	300 mm2 35 kV, MV-90, TR-XLPE, Direct Bury, 1/3 Conc. Neutral	50 m spool	2,000	180	360,000
	185 mm2 35 kV, MV-90, TR-XLPE, Direct	50 m spool	1,400	84	117,600

	Bury, 1/3 Conc. Neutral				
	120 mm2 35 kV, MV-90, TR-XLPE, Direct Bury, 1/3 Conc. Neutral	50 m spool	1,000	72	72,000
	70 mm2 35 kV, MV-90, TR-XLPE, Direct Bury, 1/3 Conc. Neutral	50 m spool	800	90	72,000
Substation/Grid Interconnection	MV Switchgear	Each	150,000	1	150,000
	Main Transformer, 132/34.5 KV, 27/36/45MVA	Each	450,000	1	450,000
	Grid Interconnection and Power Evacuation using breaker and a thirdbusbar arrangement	Each	5,879,000	1	5,879,000
Low Voltage	LV Distribution	Each	50,000	1	50,000
Instrumentationand Control	Monitoring System	Each	25,000	1	25,000
	Instrumentation	Each	20,000	1	20,000
Total Balance of System—Electrical					9,151,600
Civil Works					
Civil Works	Access Roads	sq. meters	8	30,000	240,000
	Land Preparation	each	400,000	1	400,000
	Cable Routing	each	100,000	1	100,000
	Fencing	meters	115	6,000	690,000
	Electric Fencing	meters	500	1,000	500,000
	Water Pipeline	meters	14	10,000	140,000
	Control Room	each	500,000	1	500,000
	Security System	each	100,000	1	100,000
Total Civil Works					2,670,000
Total Supply					38,081,600
Services					
Labor	Construction Labor	man hrs.	5	420,000	2,100,000
	Erection Labor	man hrs.	125	48,000	6,000,000

Owner’sEngineer	Owner’s Engineer	Man days	1,750	200	350,000
Total Labor					$8,450,000
Soft Costs					
EnvironmentalCosts	Project Environmental RemediationCosts	each	400,000	1	400,000
Land Costs	Project Land Costs	each	100,000	1	100,000
DevelopmentCosts	Environmental, technical and legalconsulting	each	135,000	1	135,000
FinancingExpenses	Financial Consulting	each	80,000	1	80,000
Insurance	Project Insurance Costs	each	100,000	1	100,000
Total Soft Costs					810,000
Contingency, Spares and Contractor Margin					
Contingency Factor		%	6%		2,876,160
Recommended Spares		%	0.5%		239,680
Contractor Margin		%	10%		4,793,600
Total Contingency, Spares and Contractor Margin					7,909,400
Total Capital Expenditure, Excluding IDC					55,845,440
Total Capital Expenditure, with IDC					57,030,000

Source: based on Ken-Gen study.

Modules and Inverters

The representative modules identified were Trina TSM-DE14A (II) 340 W modules of which 139,800 units would need to be installed in the Base Case Design. The total estimated cost of the solar modules is US$16.6 million (US$119 on a unit basis) or US$0.35/Wdc, which is in line with most recent cost estimates for Tier 1 solar modules[19].

The Base Case Design also assumes 17 inverters (SMA Sunny Central 2500-EV 2500 kW) with integrated transformers. The cost for each inverter is estimated at US$200,000 with a total cost of US$3.4 million.

Balance of System—Structural

Racking System: The Base Case Design racking system is NexTracker’s Horizon Single Axis Tracking System. This systemconsists of 1,376 90-module NexTracker Horizon Rows and 266

60-module NexTracker Horizon Rows.The total cost of the racking system is estimated at US$4.7 million. The NexTracker Horizon systems are self-powered and do not require any external power source[20].

The biggest cost driver in a tracking system is the availability and price of raw materials such as steel and other metals. The prices for these commodities can vary significantly based on geographic location. Most of the world's prominent solar tracking companies have fabrication factories in various parts of the world and price the system based on Project location.

Foundations: Based on the findings, it has been assumed that the Project would use approximately 17,500 earth-screw foundations at an estimated unit cost of US$120 and total cost of US$2.1 million[21]. The specific type of foundation, size, and cost will be determined based on thegeotechnical investigation to be conducted by the EPC contractor. Similar to racking systems, thecosts for these foundations are dependent on the price of steel and geographic location.

In most parts of the world, driven pile foundations are usually the least expensive alternative when suitable for the ground conditions. Earth screw foundations are typically more expensive and ballasted foundations are often the most expensive. Generally, foundation costs make up a relatively small portion of the PV solar project capital costs and an increase/decrease in foundation costs is not expected to have a significant impact on project profitability. The amountof Project CAPEX associated with foundation work for the Base Case is approximately 4%. Assumingan extreme variance of +25% from the Base Case estimate of foundation costs, the equity IRR would decrease by 0.3%.

Substation/Grid Interconnection: The technical configuration of the Project was originally designed for a system voltage of 34.5 kV.Since KenGen uses a standard 132/11 kV transformer for its facilities, the Project's main transformeris expected to have a 132/11 kV rating. A Project design using a 132/11 kV transformer is expectedto increase the current capacity in the system by three times (as the inverters are connected in a daisy-chain arrangement) and therefore requires either increasing the number of feeders and additional bays into the switchgear or tripling the quantity of MV cables. The cost of the MV transformer and Switchgear is US$0.6 million.

The grid interconnection scheme was finalized. After detailed investigation of costs and practical constraints, it was determined that the recommended point ofinterconnection is 3.28 km northwest of the Kamburu 132 kV substation along the Kamburu- Masinga 132 kV line. A three breaker 132 kV loop-in, loop-out switching station will be used for grid interconnection. Per KenGen's instruction, the project will incorporate a breaker-and-a-thirdarrangement for the switching station. The estimated cost for grid interconnection using this scheme is US$5.8 million.

Medium Voltage Cables: The medium voltage cable for utility-scale projects collect the inverter output current in a radial, or daisy-chain, configuration. This causes current to increase after passing through each inverter and thus requires increasing the size of the cable from 70 mm^2 to 300 mm^2.

The change in system voltage (11 kV from 34.5 kV) requires tripling the amount of MV cables usedin the Project. This has increased the Project cost by approximately US$400,000.

Table 11: MV Cables

DESCRIPTION	UNIT	UNIT PRICE	QTY	TOTAL
300 mm^2 35 kV, MV-90, TR-XLPE, Direct Bury, 1/3Conc. Neutral	50 m spool	US$ 2,000	180	US$ 360,000
185 mm^2 35 kV, MV-90, TR-XLPE, Direct Bury, 1/3Conc. Neutral	50 m spool	US$ 1,400	84	US$ 117,600
120 mm^2 35 kV, MV-90, TR-XLPE, Direct Bury, 1/3Conc. Neutral	50 m spool	US$ 1,000	72	US$ 72,000
70 mm^2 35 kV, MV-90, TR-XLPE, Direct Bury, 1/3Conc. Neutral	50 m spool	US$ 800	90	US$ 72,000

Source: based on Ken-Gen study.

Civil Works and Services

Project civil works includes land preparation (which includes drainage system), access roads, cable routing, control room building, security system, fencing (electric and non-electric), and water pipeline. The total costs for the civil works is estimated at US$2.6 million

Services

The total estimated man-hours for construction labour is 420,000 and erection labour is 48,000. The estimated total labour costs for the Project are US$8.1 million assuming a majority of Kenyan labour for construction and a majority of foreign labour for erection.[24]

The total estimated man-days for Owner's Engineer is 200 with a cost of US$350,000.

Soft costs

The estimate for Project soft costs includes the following:

- Environmental and Social Mitigation Costs of US$400,000.
- Land Costs of US$100,000.
- Development Costs of US$135,000. Development costs include environmental, technical, and legal consulting costs.
- Financing Expenses of US$80,000.
- Project Insurance cost of US$100,000.

Contingency, Spares and Margins

Contingency: Project contingencies are estimated at US$2.87 million, which corresponds to 6% of total Project supply and services.[25] The contingency factor includes the potential for schedule extension due to possible long lead times for substation/grid interconnection equipment, limited PV Solar expertise in Kenya, and taking into consideration that the Project has yet to receive indicative or binding EPC proposals.

Margin: The EPC contractor margin is estimated at US$4.8 million, which corresponds to 10% of total supply and services.

6.3.2 Operating expenses

Project operating expenses are divided into i) components, ii) employees, and iii) insurance. Operating expenses for the Project are estimated at US$970,000 during the first year of operationsand are escalated each year by inflation (U.S. PPI). It is assumed that KenGen would enter into anO&M service agreement with the EPC contractor for a minimum of three years. The outsourced services include the following:

- Maintenance, repair, and replacement of modules and other electrical equipment.
- Two washings/cleanings of solar modules per year. A conservative assumption of two annual cleanings has been assumed to account for the uncertainty factorassociated with regions that have limited experience with PV solar plants.
- A yearly inspection of the power plant.
- Two vegetation cleanings per year. This could be adjusted after observing vegetation growthrates at the site.
- General administration and security of the Power Plant
- Maintenance, repair, and replacement for inverters. The expenses include routine maintenance, annualized inverter replacement, and personnel costs.[26]

In addition to the O&M contract, the Base Case assumes two full-time KenGen employees for the supervision of (and interface with) the third-party O&M contractor, annual environmental/social expenses, and insurance. The details of operating expenses are provided in the following Table.

Table 12: Annual Operating Expenses

DESCRIPTION	UNIT PRICE	UNIT	QTY	TOTAL
Outsourced Equipment/Services				
Spare Parts/Maintenance CAPEX	US$100,000	US$	1	US$100,000
Cleaning/Washing	US$100,000	US$/Wash	2	US$200,000
Annual Plant Inspection	US$20,000	US$	1	US$20,000
Administration	US$15,000	US$	1	US$15,000
Security	US$24,000	US$	1	US$24,000
Vegetation Management	US$20,000	US$/Cleaning	2	US$40,000
Inverter Maintenance / Replacement	US$320,000	US$	1	US$320,000
KenGen Employees				
Plant Supervisors	US$20,000	US$/Employee	2	US$40,000
Environmental Costs				
Annual Environment/Community Costs	US$36,000	US$	1	US$36,000
Insurance and Soft Costs				
Project Insurance	US$175,000	US$	1	US$175,000
Total Operating Expenses, Base Year				US$970,000

Source: based on Ken-Gen study.

7 FISCAL AND FINANTIAL ANALYSIS

7.1 PROJECT FINANCING

The $199.9 million capital costs of the new plant will be funded by 70% debt and 40% equity financing on a project finance basis. The debt financing will come from a Multilateral Bank. The equity financing will be provided by the foreign IPP, NPC.

The real interest rate of the loan is 7% and the principal of the loan will be repaid in 15 equal consecutive annual instalments starting in 2024. Interest accrued on the loan balance from previous period is paid in the current period, on a continuous basis.

Note that all investment costs associated with the solar plant will be paid for by the foreign IPP excluding additional investments needed in new transmission lines to connect wind farm into national grid. At the same time, the reliability costs due to intermittent and non-dispatchable nature of wind power will be paid by the public utility as part of operating cost.

- **Sources of Funds for New Plant: Funding ratios**

Debt	70%
Equity	30%

Source: Author's designated parameters

7.2 ESTIMATION PARAMETERS

Working Capital

- Accounts Receivables will be 8% of the total sales revenue
- Accounts Payables will be 20% of the total fixed costs
- Cash Balances will be 15% of the total fixed costs

Since utility will pay the foreign IPP in exchange for wind power, account receivables of the IPP are account payables of the utility.

Economic Life and Residual Value

The economic (useful) life of plants (all investments combined) is 50 years. The residual values will be estimated for:

- All new plant's capital cost items except foundations, development costs, other, road & site work and Interest during construction for foreign IPP.
- All costs of transmission lines (i.e. materials and construction) for public utility.
- Straight-line depreciation method will be used in determining the residual value of the project assuming no major capital replacements for the duration of the project. The project will be evaluated for an operating life of 20 years; assets will be liquidated at their book value.

Corporate Taxation

The project will be subject to the corporate income tax (CIT). The rate of CIT is 30% of taxable income. Note that excise tax paid on carbon credits is not deductible from income tax.

Depreciation

The tax law allows a full deduction of the depreciation and interest expenses. All capital costs of the new plant, excluding development costs and interest during construction will be depreciated (for tax purposes) over a tax life of 20 years using a straight-line depreciation method. Soft capital cost items such as development costs and interest accrued and paid during construction will be amortized over 5 years, once the project starts operation.

Table 13 - Depreciation assumptions

Economic Life of Plant	50	*Years*
Tax Life of All Assets Except Soft Capital Assets	20	*Years*
Tax Life of Soft Capital Costs	5	*Years*

Source: Author's designated parameters

Inflation and Exchange Rate

The Kenyan domestic and U.S. external inflation rates are 5% and 2%, respectively. Inflation rates in both countries are assumed to remain constant during the life of the project.

The real exchange rate of KS/$ is 105 and it is assumed to remain constant during the life of the project (i.e. 0 rate of appreciation/depreciation factor). The projected nominal Exchange rates in the following years will be changing with respect to changes in the relative inflation rates between US$ to KS.

Discount Rate

The required rate of return (discount rate) by equity holders is 12%.

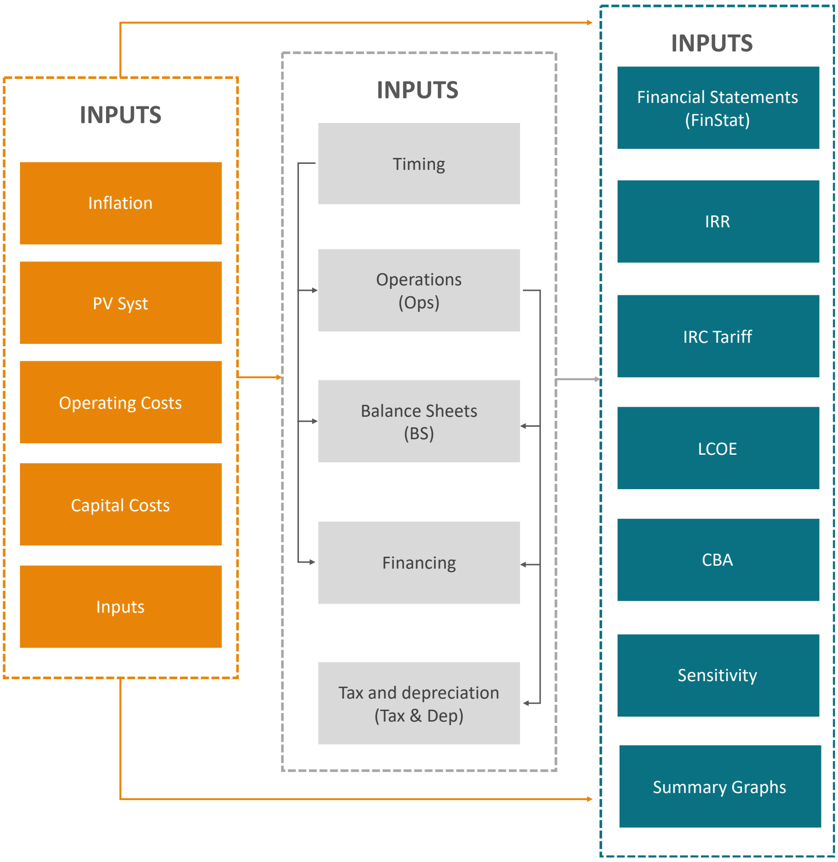
7.3 FINANCIAL ANALYSIS

The main objective of this assignment is to use the financial and sensitivity analysis of the power plant to determine whether this project is financially attractive to justify the private investor's participation, as well as evaluate its ability to service the debt obligations. It will also assist to justify the public utility's investments in new transmission line capacity.

7.3.1 Model Structure and Methodology

Figure 13 illustrates the MS Excel financial model used in this analysis. Each boxrepresents a worksheet (or tab) in the model.

Figure 13: Model Structure



Source: based on Ken-Gen study.

The model is organized according to three main worksheet types: inputs, calculations and cash flows. Inputs contain all the assumptions which drive the model. Calculation worksheets are used to perform most of the model's calculations. The Cash flow worksheets produce the finished calculations and values which are the results of the model.

The major components of each worksheet are as follows:

Inputs Worksheets

- **Inflation:** Calculates the U.S. Producer Price Index (PPI) as an inflation index for revenue and O&M escalation.

- **Energy Production:** This spreadsheet summarizes the generation projections from PVSYST (monthly and annual profiles) for use in other parts of the financial model (e.g. revenue projections and other outputs based on forecasted generation). Currently, the Base Case input scenario is the P50 scenario for a Typical Meteorological Year (TMY). KenGen may use this spreadsheet in the future to run other solar resource scenarios and possibly as the base spreadsheet/model for establishing parameters for the EPC Contractor's Energy Performance Guarantee.
- **OPEX:** Input and breakdown of O&M costs and operational insurance policy. These inputs flow through to all references to operational costs in the model.
- **CAPEX:** Input and breakdown for CAPEX. These inputs flow through the investment sections and calculation of financial statements, LCOE, LCCA, and rates of return.
- **Inputs:** This is the source of all inputs/assumptions not listed in other input worksheets.
  - Timing: This is the source of all major timing flags and counters which determine when revenuesand costs occur over the modelling period.
  - Financing: Allocates investment costs between debt and equity for use in calculating NPV and rates of return.
  - Operations: Forecasts annual generation, revenues, and operating costs over the Project operations period.
  - Tax and Depreciation (Tax&Dep): Calculates depreciation (both book and tax) and calculates tax loss carry forwards and cash taxes paid on an annual basis. Book depreciationflows through the financial statements and tax depreciation is used to calculate net cash flow, LCOE, and rates of return.

Cashflows

- **IRR**: This tab calculates equity IRRs for the Project.
- **Financial Statements (FinStat):** Cash Flow Statement, Profit & Loss Statements for the Project, and the financial NVP of the project.

7.3.2 Base Case Scenario and Results

For the financial analysis, the evaluation was conducted using a Base Case set of assumptions. The major elements of the Base Case include technical configuration, commercial and financial, and tariff.

Technical Configuration: The generation output is based on the estimated P50 scenario for a Typical Meteorological Year (TMY) The main plant assumptions include the following:

- Year 1 generation of 97,219 MWh.
- Annual degradation rate of 0.6%. Since utility scale PV solar instalments are relatively new and most plants have yet to complete their useful life, actual degradation rates on installed projects carry material uncertainty. Currently, most new PV solar projects are projecting degradation rates in the range of 0.5%.
- Project operating life of 20 years. Typically, PV solar projects are assumed to have a useful life of 25+ years. In this case, an operating life of 20 years was selected to match the term of the PPA.

Commercial and Financial: The Project is assumed to have a commercial structure under which all revenues are derived from the sale of electricity to Kenya Power and Lighting Company (KPLC) under USD-denominated PPA. The Project is not designed to require any direct subsidy from the Government to supplement its revenues but does assume a tax benefit derived from accelerateddepreciation. The main commercial assumptions used are:

- Leverage Ratio: 70%
- Loan interest rate: 7%/year
- Required return on equity:12% (after taxes)
- Loan tenor: 15 years

It should be mentioned that based on conversations with Development Finance Institutions (DFIs),the interest rate for this Project could potentially be lower (in the range of 5% per year).

Tariff: The PPA Tariff for this Project is US$100/MWh under the Base Case assumptions

Table 14: Base Case Assumptions

VARIABLE	VALUE	UNIT
Net Capacity (AC)	42.5	MW
Year 1 Generation	97,219	MWh
Degradation	0.6%	%/year
Operating Life	20	Years
Commercial and Financial		
Inflation (US PPI)	1.9%	%
Required Equity IRR (nominal)	12.5%	%/year
Leverage	70%	%
Interest Rate (nominal)	6%	%
Debt Tenor	15	years
Debt Repayment Model	Equal Principal	-
Depreciation Tax Incentive	150%	%
Capital Costs	57	million USD
Operating Expenses, Year 1	970	USD 000s

Source: Own elaboration based on Ken-Gen study.

Given the structure of the model, any change in the base year tariff (year 1) will affect the tariff in each forecast period and the annualized equity return. The goal-seek function goes through a trial-and-error process by adjusting the year 1 tariff until it gets to the value at which the IRR reaches 12.5%. This goal seek approach is an effective way to calculate tariffs for a project in which the cash flows to equity change with different debt repayment profiles. Figure 17.4 illustrates how freecash flow to equity is affected by different debt tenors. If the debt tenor is shorter than the PPA period (as is often the case), equity cash flows are much higher at the end of the PPA period as debt service requires a higher share of project revenues in earlier years. In this case, the PPA tariff increases in order to compensate equity investors for the delays in equity cash flow towards the end of the PPA period.

7.3.3 Life Cycle Cost Analysis

Life cycle cost analysis is a method for expressing the entire cost of the Project over its expected useful life in a single cost in today's dollars. It is calculated by taking the present value of all costs incurred over the life of a project at the Project's WACC. The Project costs include capital expenditure of US$55.6 million, operating expenses of US$970,000 in year 1 and escalated by inflation over the life of the Project, and cash taxes paid each year. The life cycle costs of the Project is estimated in around US$69.8 million.

CAPEX investments are developed in two years. The investment total cost by item, and the percentages of investment in each year for each item is shown below.

Table 15: CAPEX and yearly investments (I)

ID	ITEM	COST USD	COST KSH	I Y1	I Y2
CX.1	Equipment - Modules	$16.636.200	$1.746.801.000	0%	100%
CX.2	Equipment - PCS	$3.400.000	$357.000.000	0%	100%
CX.3	Equipment - Electrical BOS	$2.851.920	$299.451.600	50%	50%
CX.4	Equipment - Structural BOS	$6.654.480	$698.720.400	50%	50%
CX.5	Labour	$9.506.400	$998.172.000	30%	70%
CX.6	Civil/Site Preparation	$1.901.280	$199.634.400	100%	0%
CX.7	Gen-tie Interconnection	$6.000.000	$630.000.000	100%	0%
CX.8	Spare Parts	$147.713	$15.509.865	100%	0%
CX.9	Contingency	$1.515.704	$159.148.920	50%	50%
CX.10	Contractor Profit	$7.042.542	$739.466.910	0%	100%
	Total	$55.656.239	$5.843.905.095		

Source: Own elaboration based on Ken-Gen study.

7.4 FINANCIAL ANALYSIS RESULTS

7.4.1 Part one: Independent Power Producer's (IPP's) Point of View

The financial viability of the wind power project for the foreign IPP is estimated by deducting costs of capital, operating and maintenance (outflows), taxes from the revenues from wind power sold out (inflows) to public utility and carbon credits received from wind project.

In addition, the cash flow statement from the foreign IPP's point of view also includes the cash flows created by the financing arrangements. The receipts of the loan are the cash inflows, and all the subsequent loan repayments, interests, and financing fees are cash outflows. Unlike the lender's point of view, which looks at the debt service ratios to assess the bankability of the project, the evaluation criteria for assessing the project's net worth to the foreign IPP is the Net Present Value (NPV), and to a lesser extent, the Internal Rate of Return (IRR). The computation of NPV and IRR are based on the annual net cash flows to equity holders (i.e. dividends received by equity holders less their equity contributions).

Table below shows the main results obtained from the financial analysis worksheet. The lines described are:

- Total Inflows: The revenues from electricity power sales (at the price of 150 USD/MWh), carbon credits (at 15 USD/TonCo2) and the economical residual value.
- Total Capital Costs of new plant: Correspond to the full CAPEX amount on year 2021 and 2022.
- Total Operational Costs: Corresponds to the full OPEX (fixed and variable costs) from year 2023 to the end of the project horizon scope.
- Taxes: Corresponds to the taxes paid by yearly exercise.
- Total Financing Inflows: Corresponds to the Loan Disbursements at years 2021 and 2022.
- Total Financing Outflows: Corresponds to the interest and capital outflows to repay debt.
- Cash Flow Owner Perspective: Corresponds to the final cash flow from the owner perspective (including financing movements).

Table 16: Main results from financial analysis (Millions KSc)

	2020	2021	2022	2023	2024
Total Inflows	$ -	$ -	$ -	$ 1.660	$ 1.541
Total Capital Costs of New Plant	$ -	$ 1.723	$ 4.121	$ -	$ -
Total Operational Costs	$ -	$ -	$ -	$ 441	$ 410
Taxes	$ -	$ -	$ 156	$ 166	$ 176
Total Financing Inflows	$ -	$ 1.723	$ 4.121	$ -	$ -
Total Financing Outflows	$ -	$ -	$ 108	$ 630	$ 594
Cash Flow Owner Perspective	$ -	$ -517	$ -1.344	$ 434	$ 370

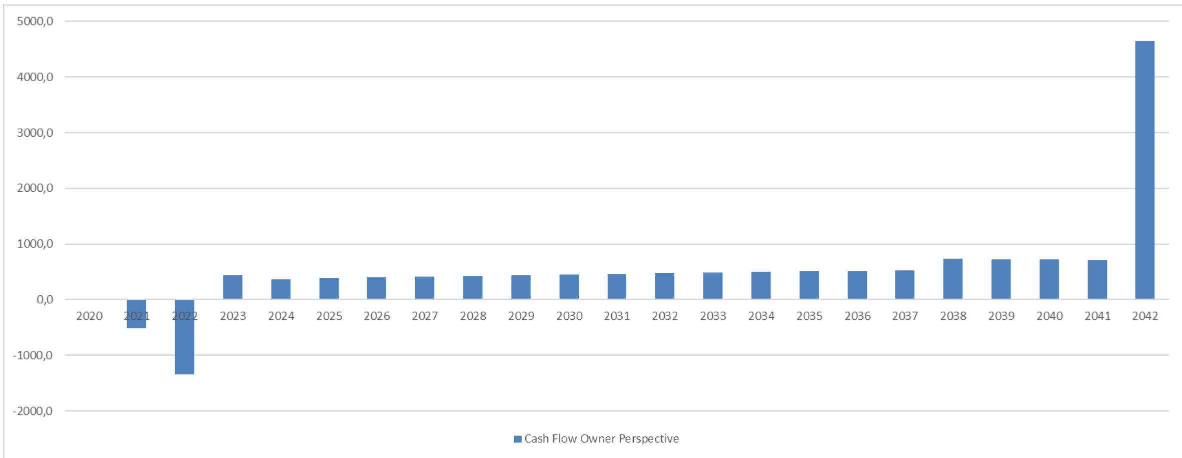
	2025	2026	2027	2028	2029
Total Inflows	$ 1.531	$ 1.522	$ 1.513	$ 1.504	$ 1.494
Total Capital Costs of New Plant	$ -	$ -	$ -	$ -	$ -
Total Operational Costs	$ 410	$ 410	$ 410	$ 410	$ 410
Taxes	$ 185	$ 193	$ 207	$ 214	$ 221
Total Financing Inflows	$ -	$ -	$ -	$ -	$ -
Total Financing Outflows	$ 559	$ 525	$ 492	$ 461	$ 430
Cash Flow Owner Perspective	$ 386	$ 402	$ 417	$ 426	$ 440

	2030	2031	2032	2033	2034
Total Inflows	$ 1.485	$ 1.476	$ 1.466	$ 1.457	$ 1.448
Total Capital Costs of New Plant	$ -	$ -	$ -	$ -	$ -
Total Operational Costs	$ 410	$ 410	$ 410	$ 410	$ 410
Taxes	$ 228	$ 234	$ 241	$ 246	$ 252
Total Financing Inflows	$ -	$ -	$ -	$ -	$ -
Total Financing Outflows	$ 401	$ 372	$ 344	$ 318	$ 292

	2020	2021	2022	2023	2024
Cash Flow Owner Perspective	$ 453	$ 465	$ 477	$ 488	$ 499
	2035	2036	2037	2038	2039
Total Inflows	$ 1.438	$ 1.429	$ 1.420	$ 1.410	$ 1.401
Total Capital Costs of New Plant	$ -	$ -	$ -	$ -	$ -
Total Operational Costs	$ 410	$ 410	$ 410	$ 410	$ 410
Taxes	$ 257	$ 261	$ 266	$ 265	$ 263
Total Financing Inflows	$ -	$ -	$ -	$ -	$ -
Total Financing Outflows	$ 267	$ 243	$ 220	$ -	$ -
Cash Flow Owner Perspective	$ 509	$ 519	$ 528	$ 734	$ 726
	2040	2041	2042		
Total Inflows	$ 1.392	$ 1.383	$ 5.312		
Total Capital Costs of New Plant	$ -	$ -	$ -		
Total Operational Costs	$ 410	$ 410	$ 410		
Taxes	$ 262	$ 261	$ -		
Total Financing Inflows	$ -	$ -	$ -		
Total Financing Outflows	$ -	$ -	$ -		
Cash Flow Owner Perspective	$ 718	$ 710	$ 4.641		

Source: Own elaboration based on Ken-Gen study.

Figure 16: Owner's perspective cash-flow



Source: Own elaboration based on Ken-Gen study.

From the owner's perspective cash flows statement, using a discount rate of 12%, the financial analysis shows that the project is financially feasible, with a positive NVP @12% of 1.363 Million KSc-, and an Internal Rate of Return (IRR) at the order of 22.3%.

Table 17 - Owner's perspective indicators

NPV (@12%)	1.363 MM KSc
IRR	22,3%

Source: Own elaboration based on Ken-Gen study.

7.4.2 Part Two: Banker's Point of View

From Lender's perspective, the difference between the project's inflows and outflows indicates the project's annual net cash flows before financing, which forms the foundation for evaluating the ability of the project to service the debt for its financing. The results of the banker's or total investment point of view are seen from the perspective of the debt service ratios, the annual debt service coverage ratios, and loan life cover ratios. The values of these variables serve to be the targeted criteria in the assessment of the project's sustainability and the ability to repay its debt.

Table 18 - Banker's point of view Cash Flow (Millions KSc.)

Debt Service Coverage Ratios (Nominal)		2021	2022	2023	2024	2025	2026	2027	2028	2029
Cashflow Available for Debt Service and Debt Service										
Cashflow Available for Debt Service										
Cashflow Available for Debt Service	*Million KSc*	-	-	1.231,7	1.172,2	1.206,7	1.242,3	1.279,1	1.310,0	1.349,3
Debt Service										
Interest Payment During Operations	*Million KSc*	-	119,2	421,9	405,3	387,5	368,2	347,4	325,1	301,2
Principal Payment	*Million KSc*	-	-	307,7	316,8	326,1	335,7	345,6	355,7	366,2
Total Debt Service	*Million KSc*	-	119,2	729,6	722,1	713,6	703,9	693,0	680,8	667,4
Annual Debt Service Coverage Ratio (ADSCR)										
Cashflow Available for Debt Service	*Million KSc*	-	-	1.231,7	1.172,2	1.206,7	1.242,3	1.279,1	1.310,0	1.349,3
Total Debt Service	*Million KSc*	-	119,2	729,6	722,1	713,6	703,9	693,0	680,8	667,4
ADSCR	*#*	-	-	1,69	1,62	1,69	1,76	1,85	1,92	2,02
Loan Life Coverage Ratio (LLCR)										
Outstanding Debt Balance	*Million KSc*	1.266,6	4.484,0	4.308,1	4.118,1	3.913,1	3.692,5	3.455,5	3.201,5	2.929,4
Nominal Interest Rate	*%*	9,1%	9,1%	9,1%	9,1%	9,1%	9,1%	9,1%	9,1%	9,1%
Cashflow Available for Debt Service	*Million KSc*	-	-	1.231,7	1.172,2	1.206,7	1.242,3	1.279,1	1.310,0	1.349,3
PV Cash Flow Available for Debt Service	*Million KSc*	-	-	11.791,7	11.525,2	11.299,2	11.015,0	10.665,9	10.244,7	9.751,4
Outstanding Debt Balance	*Million KSc*	1.266,6	4.484,0	4.308,1	4.118,1	3.913,1	3.692,5	3.455,5	3.201,5	2.929,4
LLCR	*#*			2,74	2,80	2,89	2,98	3,09	3,20	3,33

Debt Service Coverage Ratios (Nominal)		2030	2031	2032	2033	2034	2035	2036	2037
Cashflow Available for Debt Service and Debt Service									
Cashflow Available for Debt Service									
Cashflow Available for Debt Service	*Million KSc*	1.389,9	1.431,9	1.475,3	1.520,1	1.566,4	1.614,2	1.663,6	1.714,7
Debt Service									
Interest Payment During Operations	*Million KSc*	275,6	248,3	219,1	187,9	154,8	119,5	82,0	42,2
Principal Payment	*Million KSc*	376,9	388,0	399,4	411,2	423,3	435,7	448,6	461,8
Total Debt Service	*Million KSc*	652,6	636,3	618,5	599,1	578,0	555,2	530,6	504,0
Annual Debt Service Coverage Ratio (ADSCR)									
Cashflow Available for Debt Service	*Million KSc*	1.389,9	1.431,9	1.475,3	1.520,1	1.566,4	1.614,2	1.663,6	1.714,7
Total Debt Service	*Million KSc*	652,6	636,3	618,5	599,1	578,0	555,2	530,6	504,0
ADSCR	*#*	2,13	2,25	2,39	2,54	2,71	2,91	3,14	3,40
Loan Life Coverage Ratio (LLCR)									
Outstanding Debt Balance	*Million KSc*	2.638,6	2.328,2	1.997,2	1.644,8	1.269,9	871,5	448,6	-
Nominal Interest Rate	*%*	9,1%	9,1%	9,1%	9,1%	9,1%	9,1%	9,1%	9,1%
Cashflow Available for Debt Service	*Million KSc*	1.389,9	1.431,9	1.475,3	1.520,1	1.566,4	1.614,2	1.663,6	1.714,7
PV Cash Flow Available for Debt Service	*Million KSc*	9.170,0	8.491,2	7.704,5	6.798,6	5.761,0	4.578,0	3.234,7	1.714,7
Outstanding Debt Balance	*Million KSc*	2.638,6	2.328,2	1.997,2	1.644,8	1.269,9	871,5	448,6	-
LLCR	*#*	3,48	3,65	3,86	4,13	4,54	5,25	7,21	1,00

Source: Own elaboration based on Ken-Gen study.

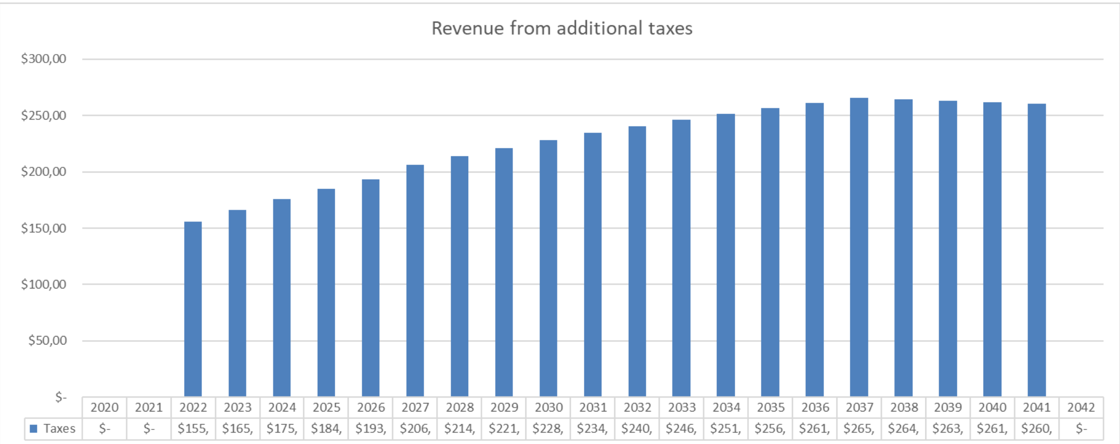
Seven Forks solar generation power plant project shows a very healthy yearly LLCR and DSCR, where every year both values are over 1,5 and 2,0, respectively. This indicator shows that the project is bankable, and it will be feasible that investments banks will be willing to finance the leverage defined proportion of CAPEX.

7.4.3 Part Three: Public Finance's Point of View

This point of view corresponds to the changes on taxation from the government's point of view. Thus, if the project collects more taxes, or requires more subsidies, there will be an appreciable change in the public founds cash flow. The results will be shown in the following sections.

As there are not subsidies related to this project, the only change from the public finance's point of view (or budgetary standing), the additional taxes recollection will be shown in the following figure.

Figure 17: Government revenues from additional Taxes



Source: Own elaboration based on Ken-Gen study.

8 ECONOMIC AND STAKEHOLDERS' ANALYSIS

The economic appraisal evaluates the impacts of the project on the entire society (in this case both country economy and global economy). The main objective of the economic analysis is to quantify these impacts in terms of the economic costs and benefits of the solar power plant to be constructed. To achieve this purpose, an economic resource flow statement is developed for the project, which translates all financial transactions (i.e., receipts and expenditures) into benefits and costs in the economic resource statement to reflect their value to the society. Estimation of the economic benefits and costs are based on well-established principles of applied welfare economics.

In the context of applying the integrated appraisal framework, the economic evaluation is causally linked to the financial cash flow statement of the project by simply converting the financial cost of all project inputs into the economic costs. To guarantee a consistent transformation from the financial analysis into economic analysis, economic prices are used. Once the conversion factors are computed, they can be multiplied by the respective financial values to obtain the corresponding economic values.

Once the financial values are converted into their economic costs and benefits, the economic appraisal will proceed to examine whether the project is economically viable for the country. To conduct economic appraisal, the following parameters and assumptions must be defined.

8.1 ECONOMIC PARAMETERS AND ASSUMPTIONS

National Parameters

The National Parameters (economic prices) are those estimated and presented in the Manual:

- The Social Discount Rate (SDR)
- The Shadow Wage Rate (SWR)
- The Shadow Exchange Rate (SER)
- The Standard/Generic Conversion Factor (SCF)

Imported Goods

Imported capital items are not subject to any import duty or VAT. These capital items include solar plated, electrical equipment, machinery & equipment and its related costs.

- Imported input items are not subject to any import duty, but subject to a 12% VAT.
- Similarly, tradable components of inputs of the infrastructure & civil works are subject to the 12% VAT when purchased. There is zero import duty on these tradable inputs of infrastructure and civil works.
- The heavy fuel oil is imported and is subject to a 15% import duty levied on the border price (CIF price). It is exempted from VAT, but subject to a 5% excise tax.
- The revenue from carbon credits is subject to a 6% excise tax which will be paid to government of Putnam.

Summary of Taxes and Duties on Imported Inputs

The taxes and duties on imported capital and other inputs are summarized in Table below.

Table 19: Summary of Tax and Duty Rates for Tradable

Categories	Rates
Import Duty on Imported Capital Items	0%
VAT on Imported Capital Items	0%
VAT on All Other Imported Inputs	12%
VAT on Imported Services	12%
Import Duty on Petrol (heavy fuel oil)	15%
Excise Tax on Petrol (heavy fuel oil)	5%
Excise Tax on Carbon Credits	6%

Source: Own elaboration based on Ken-Gen study.

Labour

- The domestically employed labour is composed of 90% skilled and 10% unskilled employees. The skilled labour is subject to 20% personal income tax whereas the unskilled category to 10%. The social security contributions by the skilled and unskilled employees are estimated to be 15% and 10%, respectively. It is assumed that in the absence of this project, skilled and unskilled labour would have spent 90% and 50% of their time, respectively, employed elsewhere.

- Foreign engineers are also employed by the project to work on the activities covered by the EPC contract. The estimation of the SWR in the case of foreign labour is like the approach used for domestic labour except that it incorporates the foreign exchange premium forgone on the remittances of net income abroad, as well as account for taxes collected on the consumption (of foreign labour) in Putnam. The share of the income repatriated is estimated to be 70%.

Working Capital

- The conversion factor for changes in accounts receivable is same as the conversion factor for solar power payments to foreign IPP, adjusted for SER. The conversion factor for the desired cash balance is assumed to be 1.
- The change in Foreign IPP's accounts payable with other suppliers has the same conversion factor as fixed O&M expenses.

International trade and domestic consumption taxes

- Imported Goods

Imported capital items are not subject to any import duty or VAT. These capital items include: wind turbines, electrical equipment, machinery & equipment and its related costs.

Imported input items are not subject to any import duty, but subject to a 12% VAT. Similarly, tradable components of inputs of the infrastructure and civil works are subject to the 12% VAT when purchased.

The heavy fuel oil is imported and is subject to a 15% import duty levied on the border price (CIF price). It is exempted from VAT, but subject to a 5% excise tax.

The taxes and duties on imported capital and other inputs are summarized in Table below.

Table 20: Summary of Tax and Duty Rates (Tradable)

CATEGORIES	RATES
Average Import Tariff on Imported Capital Items	0%
VAT on Imported Capital Items	0%
VAT on All Other Imported Inputs	12%
VAT on Imported Services	12%
Import Duty on Petrol (heavy fuel oil)	15%
Excise Tax on Petrol (heavy fuel oil)	5%

Source: Own elaboration based on Ken-Gen study.

- Non-Tradable Goods

VAT on non – tradable services is 11%.

Infrastructure and civil works that are the non-tradable items are also covered by the contract. Non-tradable inputs of the infrastructure and civil works are sourced domestically and are subject to the 10% VAT when purchased.

The demand and supply elasticities for the non-tradable items are provided in Table below.

Table 21: Demand and Supply Elasticities for Non-Tradable Inputs

NON-TRADABLE DATA	DEMAND ELASTICITY (H)	SUPPLY ELASTICITY (E)
Non-tradable infrastructure and civil works	-1	2
Cement and other-non-metallic products	-1	3
Business and other services	-1	3
Other non-traded items	-1	3

Source: Own elaboration based on Ken-Gen study.

The taxes on domestically sources inputs are summarized in the table below.

Table 22: Summary of Tax and Duty Rate (Tradable)

CATEGORIES	RATES
VAT on Domestic Sourced Capital Items	13.0%
VAT on Non - Tradable Components of Civil Works Inputs	12%
VAT on Non-Traded Services	11%

Source: Own elaboration based on Ken-Gen study.

- Transport and Handling Assumptions

The transport and handling assumptions are summarized in the table below.

Table 23: Transport and Handling Assumptions

VARIABLE	% OF (CIF+IMPORT DUTY)	CF
Port handling	5%	0.94
Cost of transport, port – project	5%	0.92

Source: Own elaboration based on Ken-Gen study.

Other Conversion Factors

In order to compute the economics of Seven Forks solar plant net benefits, every market value input data must be converted into economic values, that reflects the real resource uses of the project, regardless of taxation distortions. The Economic Evaluation Model contains every Conversion Factor (CF) calculation in detail, and here it will be presented a summary of the calculated CF.

Table 24: Summary of economic CFs

Country Cash-flow	CF	
Fuel Cost Savings from Combine Cycle Plant	0,87	CF for fuel oil
Fuel Cost Savings from Single Cycle Plant	0,87	CF for fuel oil
Residual Value of Assets	1,00	No distortion, CF of 1
Corporate Taxes Received from Wind Power Sales	1,00	Assumed to be 1
Excise Taxes Received from Carbon Revenues	1,00	Assumed to be 1
Wind Power Payments to Private IPP	1,12	CF for Wind Power Payments to private IPP, adjusted for FEP
Transmission Lines Capital Costs	0,94	Average CF for road & site work, building & foundation, and machinery &equipment)
Reliability Costs of Power Supply	0,87	CF for fuel oil
Change in Accounts Payable (change in A/R of private IPP)	1,00	Assumed to be 1
Global Cash-flow		
Fuel Cost Savings	0,87	CF for fuel oil
Carbon Credits	1,19	CF for exported goods and services (Financial price of carbon, adjusted for excise tax and FEP is assumed to be a Proxy for economic environmental benefits)
Residual Value of Assets	1,00	No distortion, CF of 1
Change in Account Receivables	1,00	Assumed to be 1
Foundations	0,97	CF for non-tradable civil works
Electrical	0,90	CF for imported capital items
Turbines	0,90	CF for imported capital items
Capital Spares	0,90	CF for imported capital items
Road & Site Work	0,97	CF for Non-tradable civil works
Building & Foundation	0,97	CF for Non-tradable civil works
Machinery & Equipment	0,90	CF for imported capital items
Other (Training, Spares, G&A)	0,79	Average CF for foreign labour, skilled local labour and imported capital items
Contingency	0,91	Weighted average CF for imported capital items (75%) and non-tradable civil works (25%)
Development Costs	1,00	CF for imported services

Transmission Lines Capital Costs	0,94	Average CF for imported capital items and non-tradable civil works
Variable O&M Expenses	0,93	Average CF for imported inputs items and non-tradable services
Fixed O&M Expenses	0,73	Average CF for local labour and non-traded services
Reliability Costs of Power Supply	0,87	CF for fuel oil
Change in Account Payables	0,73	Same as CF for Fixed O&M Expenses
Change in Cash Balances	1,00	Assumed to be 1

Source: Own elaboration based on Ken-Gen study.

8.2 ECONOMIC VIABILITY OVERVIEW

8.2.1 Economic Benefits and Costs to Country's Economy

The main economic benefits received from the solar project to the country's economy are fuel cost savings. The assumptions and calculations of the financial fuel cost savings have already been provided in the financial analysis part. The estimation of the economic fuel cost savings is done by using a conversion factor that is estimated by dividing economic price of fuel oil to its financial price. Since financial price of fuel oil includes various sets of taxes such as import tariff and VAT, the conversion factor is used to determine the true economic benefits from fuel savings. In addition, corporate income taxes from foreign IPP and excise taxes earned from carbon credits are added into economic benefits generated from the solar project. The net of tax value of the carbon credits is received by the IPP who is assumed to be a foreign entity. Personal income taxes and additional earnings from local labour employed by the foreign IPP are also part of the economic benefits from the solar project.

Since the solar project is owned by the foreign IPP and public utility pays for each MWh of electricity supplied, the solar power payments from utility to the foreign IPP are outflows from the country economy’s point of view. Furthermore, the payments to the foreign IPP are made in international currency, so these payments are adjusted for the foreign exchange premium to estimate the true economic costs paid by the country. The rest of the economic costs of the project are estimated free of taxes but now include the foreign exchange premium that arises from the variety of distortions associated with the markets for tradable goods.

8.2.2 Global Economy's Point of View

This point of view measures economic benefits and costs from the perspective of the global economy. It captures all the externalities that accrues to the country and outside the country due to the solar power project.

This point of view measures economic benefits and costs from the perspective of the global economy. It captures all the externalities that accrues to the country and outside the country due to the solar power project.

In order to generate additional MWh of electricity, combine cycle plant consume 0.145 tons of fuel oil while single cycle plant consume 0.187 tons of fuel oil. It is assumed that annual increase in fuel consumption will be 1% regardless of power unit. In other words, the reduction in plant efficiency is assumed to be the same across power plants due to depreciation of physical capital (ageing of plant).

Given the intensity of solar power, the fractions of fuel oil saved from combined cycle power plant (off peak time load plant) will be 40% and 60% of heavy fuel oil saved from single cycle power plant (peak time load plant).

Note that cost of heavy fuel oil is estimated when the price of crude oil is 75$/barrel which is assumed to remain unchanged throughout the project life. The relationship between cost of crude oil price and cost of fuel oil for electricity generation per tonne is given using the following formula:

$$Fuel\ oil\left(per\ tonne\right)_t = 0.629\ Crude\ oil\left(per\ barrel\right)_t + 0.185\ Crude\ oil\left(per\ barrel\right)_{t-1}$$

8.2.3 Economic Benefits and Costs to Global Economy

The benefits of the project to the global economy emanate from the fuel cost savings (same as in part one above) and carbon credits. These benefits are part of resource inflow to the global economy. On the resource outflow side, all resources used by solar project are deducted to account for their opportunity cost for the global economy. The resource costs are all capital equipment's and other equipment's used for operating and maintaining the solar power plant and the transmission line system.

Net Economic Benefits PV

The Economic Evaluation was performed at a rate of 12,34%, as it is estimated in the Manual. In the table below, the main lines of the evaluation are shown at present value for year 2021.

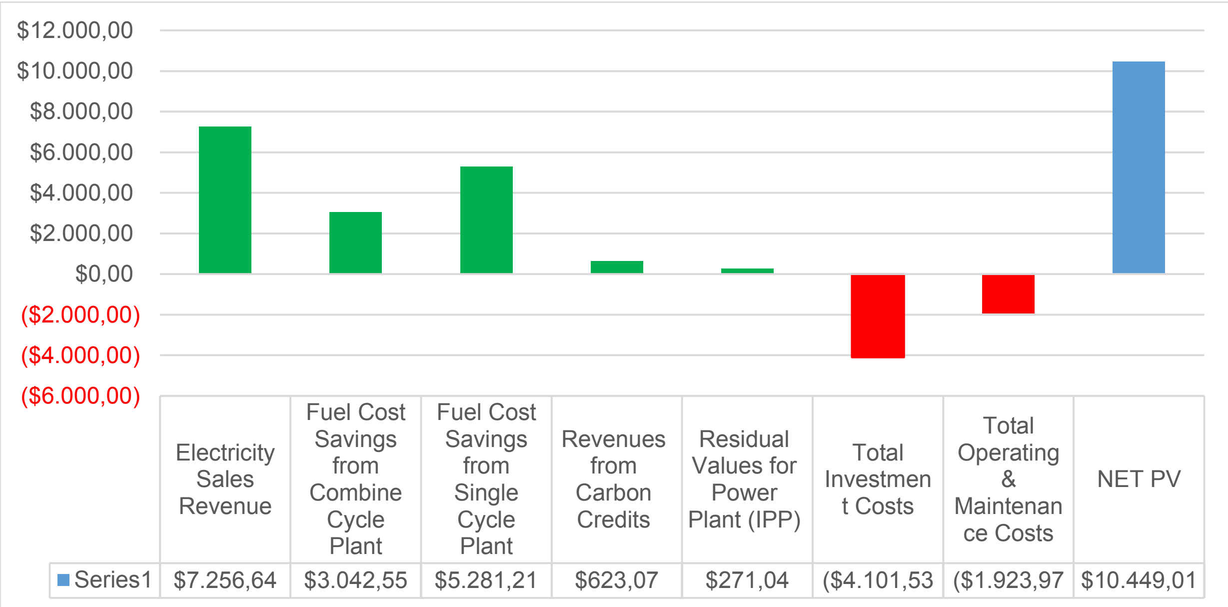
Table 25: PV of main costs and benefits (Millions KSc)

ECONOMIC BENEFITS - GLOBAL	
Electricity Sales Revenue	$7.163,44
Fuel Cost Savings from Combine Cycle Plant	$3.042,55
Fuel Cost Savings from Single Cycle Plant	$5.281,21
Revenues from Carbon Credits	$623,07
Change in Accounts Receivable	$93,20
Residual Values for Power Plant (IPP)	$271,04
Total Economic Benefits	$16.474,51
ECONOMIC COSTS - GLOBAL	$0,00
Equipment - Modules	$1.176,64
Equipment - PCS	$240,47
Equipment - Electrical BOS	$214,16
Equipment - Structural BOS	$499,70
Labour	$697,26
Civil/Site Preparation	$151,07
Gen-tie Interconnection	$476,73
Spare Parts	$10,12
Contingency	$113,82
Contractor Profit	$521,57
Total Investment Costs	$4.101,53
	$0,00
Variable O&M Expenses	$1.450,96
Fixed O&M Expenses	$449,39

Total Operating & Maintenance Costs	$1.900,34
Change in Accounts Payable	$14,70
Change in Cash Balances	$8,92
Total Economic Costs	$6.025,50
Net Global Resource Flow	$10.449,01

Source: Own elaboration based on Ken-Gen study.

Figure 14: PV of main costs and benefits (Millions KSc)



Source: Own elaboration based on Ken-Gen study.

The main differences between financial and economic evaluation are:

- The market prices for CAPEX and OPEX calculation are modified using the correspondent's conversion factors, in order to maintain the economical approach of real resource usage.
- The global (social) evaluation considers also the Fuel Cost Savings from Combine Cycle Plant and Fuel Cost Savings from Single Cycle Plant, where both items show to be very relevant in the economic NPV.

The Net Economic Present Value of this project is 29.291 MM KSh, and the Economic Internal Rate of Return is calculated at 54%. Given those results, the project is economically feasible.

9 STAKEHOLDER ANALYSIS

9.1 APPROACH

The financial and economic analysis of the integrated project analysis provides the basic data for estimating the specific stakeholder impacts. The impact on stakeholders can be calculated by subtracting the financial benefits and costs from the economic benefits and costs. They represent the externalities produced by this project.

The purpose of stakeholder analysis (also known as the distributional analysis) is to determine who gains and who loses as a result of the project. It also serves to see if the groups who were targeted to receive benefits as a result of the project will actually receive these benefits as well as to ensure that no specific group is subject to an undue burden as a result of the project. The magnitude of the impact is measured by the NPV expected to be realized by each group of the stakeholders.

After the externalities are distributed, reconciliation between the financial cash flow and economic resource flow statements with the distributive impacts is conducted. This reconciliation helps to ensure that the analysis has been carried out in a consistent manner.

9.2 RELATIONSHIP BETWEEN ECONOMIC, FINANCIAL VALUES AND EXTERNALITIES

The stakeholder analysis of any project builds on the following relationship:

$$Pe=Pf+\Sigma Extini=1$$

Where,

- Pe is the economic value of an input or output;
- Pf is the financial price of the same variable; and
- ΣExtini=1 is the sum of all the externalities that cause the economic value of an item to be different from its financial price.

In other words, the economic value of an item can be expressed as the sum of its financial price plus the value of externalities, such as taxes, tariffs, consumer/producer surpluses. On the basis of identity above, the following relationship also holds, if a common economic discount rate is applied:

$$NPVe(SDR) = NPVf(SDR) + PVe(SDR)\ (\Sigma Extini{=}1)$$

Where,

- NPVe(SDR) is the present value of the net economic benefits, discounted by the SDR;
- NPVf(SDR) is the present value of the net financial cash flow discounted by the SDR; and
- PVe(SDR)(ΣExtini=1) is the sum of the present value of all the externalities generated by the project, also discounted by the SDR.

The project generates two types of net benefits: financial net benefits, which accrue directly to those who have a direct financial interest in the project; and externalities, which are allocated to different segments of the society. The stakeholder analysis requires the following steps:

- Identifying the stakeholder impacts of the project, item-by-item, by subtracting the financial cash flow from the economic statement of benefits and costs;
- Calculating the present value of each line item's flow of externalities, using the SDR as the discount rate;
- Allocating the present value of the externalities to the relevant groups in the economy.

Table 26: Integrated project appraisal (Millions KSc in PV)

		PV Financial (Utility)	PV Externalities	Fin + Ext	PV Economic (Country)
Benefits					
Electricity Sales Revenue	*Million KSc*	7.163,4	-	7.163,4	7.163,4
Revenues from Carbon Credits	*Million KSc*	522,9	100,1	623,1	623,1
Change in Accounts Receivable	*Million KSc*	93,2	-	93,2	93,2
Corporate Income Tax Paid by IPP	*Million KSc*		7y1.057,9	1.057,9	1.057,9
Excise Taxes Paid by IPP on Carbon Revenues	*Million KSc*		-	-	-
Externalitity of Local Labor Employed by Foreign IPP	*Million KSc*		5,2	5,2	5,2
Total Benefits	***Million KSc***	7.779,6	1.163,3	8.942,8	8.942,8
Costs					
Total Investment Costs	*Million KSc*	4.101,5	170,4	4.271,9	4.271,9
Total Operating & Maintenance Costs	*Million KSc*	1.900,3	208,6	2.108,9	2.108,9
Change in Accounts Payable	*Million KSc*	14,7	-	14,7	14,7
Change in Cash Balances	*Million KSc*	8,9	-	8,9	8,9
Total Costs	***Million KSc***	6.025,5	378,9	6.404,4	6.404,4
Net Resources	***Million KSc***	1.754,1	784,3	2.538,4	2.538,4

Source: Own elaboration based on Ken-Gen study.

From this analysis, the main beneficiary stakeholders are the government, due the increase in revenues from taxes collection, and the society, because of the liberation of crude oil usage for energy supply.

10 RISK ANALISYS

10.1RISKS IDENTIFICACTION

This Section of the Report is comprised of a high-level summary of the risk assessment. The Table below lists the major risk categories along with recommendations for allocation and mitigation. The remaining sections of the Report provide a more comprehensive list of risks and greater detail regarding allocation and mitigation measures.

Table 27 - Risk Allocation and Mitigation for Seven Forks

RISK	EXPECTED IMPACT	ALLOCATION	ALLOCATION INSTRUMENT	KENGEN RECOMMENDED ACTION
Investment Cost				
Site Selection	Low	KenGen	N/A	• Engaged consultant to support KenGen in site evaluation • Evaluated KenGen land in the vicinity of the Seven Forks Hydroelectric complex to ensureland access, limited risk of conflictiveland use, and proximity to interconnection alternatives
Plant Design	Low	EPC Contractor	EPC Contract	• Design and associated risk specified as part of EPC contractor scope • Set conceptual design technical specifications in EPC Contract • Retain Owner's Engineer to supervise EPC Contractor
Capex and ConstructionDelays	Medium	EPC Contractor InsuranceProvider	EPC Contract Insurance Policies	• Lump sum turnkey EPC backed by schedule and performance guarantees, liquidated damages and security
				• Dedicated KenGen-led construction supervisory and interface team supported by an Owner's Engineer and responsible for scheduling and cost control for EPC contractor scope and any residual responsibility assumed by KenGen
				• Procure a comprehensive insurance package including builder's all-risk (or similar policy), marine cargo, general liability, and advance loss of profit
Permitting	Medium	EPC Contractor	EPC Contract	• EPC contractor responsible for procuring all construction phase permits except for the environmental permit

				• EPC contractor must perform all work in compliance with all applicable permits
				• KenGen permit compliance team to track permit procurement and compliance and interface with EPC contractor
Financing	Medium / Low	KenGen	N/A	• Competitive lender selection process with invitations to lenders that have keen interest in this type of project and can offer attractive commercial terms
				• Ensure that key risks are properly allocated to experienced providers under strong contracts (EPC, O&M, PPA, Insurance)
				• Engage financial advisor with understanding of PV projects to support the selection process and negotiation of financing documentation
Revenue				
Energy Productio n	Medium	EPC Contractor(plant) O&M Contractor (operation) Insurance Provider (Damage)	EPC Contract O&M ContractInsurance	• EPC contract and equipment supply to ensure delivery of a quality plant • O&M contractor to guarantee high operational performance and to train KenGen for future operation • Business interruption and property damage insurance to compensate for down time caused by qualifying events
		KenGen (weather)		
Energy Evacuatio n	High	EPC Contractor KenyaPower KenGen	EPC ContractPPA	• EPC contractor to construct interconnection in compliance with Grid Code and prudent practice and hand over substation directly to Kenya Power • Kenya Power to assume (at least) a portion of evacuation risk associated with problems attributable to the transmission system • KenGen to monitor transmission system planning and regulatory regime to prevent congestion (e.g. too much solar installation in certain parts of the grid)

Energy Price	High	PPA Offtaker(Kenya Power)	PPA	• Avoid unnecessary CAPEX and OPEX to ensure Project competitiveness and Energy Regulatory Commission (ERC) approval • Long term PPA in US dollars (or indexed to US dollar) • Change of law clause
OperationalCost				
Operation alCosts	Low	O&M Contractor KenGen	O&M Contract	• O&M contractor to assume most of the OPEX overrun risk in early years of operation and provide training to KenGen to control cost thereafter • KenGen to have assigned personnel responsible and accountable for any OPEX not included in the O&M contractor scope (e.g. social/community commitments, internal administration)
Safety, EnvironmentalPerformance and Social Welfare				
Safety	High	All parties	EPC Contract O&M Contract KenGen plans, policies, and procedures Training and documentation vis-a-vis the general public	• Comprehensive safety program applicable to KenGen personnel, all contractors, and all applicable community members, with zero tolerance policy for safety violations • Program of safety walks (particularly during construction) • Tracking and assessment of safety key performance indicators • Safety awareness and education programs for the greater community

Enviro mental Complian ce	Medium	All parties	EPC Contract O&M Contract KenGen plans, policies, and procedures Training and documentation vis-a-vis the general public	• Strict compliance with the Environmental and Social Impact Assessment (ESIA) and Environmental and Safety Management Plan (ESMP) • KenGen to have assigned personnel responsible and accountable for environmental compliance
Social Commitm ents	High	EPC ContractorKenGen	EPC Contract Stakeholder Engagement Plan (SEP)	• Assign responsibility for applicable tasks to the EPC contractor • KenGen to have assigned personnel responsible and accountable for environmental compliance • Emphasize delivering (or over- delivering) on all social commitments and managing expectations

Source: Own elaboration based on Ken-Gen study.

10.2 RISKS VARIABLES

The main risk variables identified are described in this section. In order to identify those risks variables, the sensitivity analysis was performed by the consultant team. First, we describe the risk variables associated with the model, and then, the sensitivity analysis was performed in order to assess the impact of each variable in the financial and economic performance indicators.

Investment Cost

The first category is comprised of risks that can lead to substantially higher investment costs compared to a base case budget (or initial expectation). Failure to maintain an investment cost level that is aligned with budget can lead to unattractive equity returns, financial stress, or project cancellation. The following sub-categories contain underlying risks that can have significantimpacts on investment cost:

- Site selection
- Plant design
- Capital expenditure and Construction
- Permitting
- Financing

Revenue

Certain risks can have a direct impact on project revenue and therefore the equity returns and general financial condition of a project. Revenue related risk can be broken down into the following sub-categories:

- Energy production
- Energy evacuation
- Energy price

Capacity volume and price (applicable for certain projects/markets but not Seven Forks Solar

Inflation

Domestic and Inflation is relevant in this appraisal, mainly considering the impact of inflation in the working capital estimation (due the accounts receivable and accounts payable) and the impact of the relative inflation between Kenia and the US on the financial loan payment distribution and amount).

Change in Crude Oil price per Barrel

Considering the main economic benefits of this project, the resources liberation for the change in the energy production matrix, due the change of energy production from petrol combustion energy supply to a solar energy supply, the changes in the future price of crude oil per barrel will impact the amount of economical externality benefits.

10.3 SENSITIVITY ANALYSIS

The base case financial and economic model consider a deterministic approach of appraisal. The parameter values in the case scenario are the following:

Domestic Inflation Rate Sensitivity	5%
Investment Cost Overrun Factor	0%
Electricity Tariff Sensitivity Factor	0%
Change in Crude Oil Price per Barrel	0%
Us Inflation Rate Sensitivity	2%

Source: Own elaboration based on Ken-Gen study.

The main results of the sensitivity analysis are described as follows.

Changes on Domestic Inflation

			Equity NPV IPP	Minimum ADSCR	Minimum LLCR	Economic NPV Country	Economic NPV Global	NPV Stakeholder
			Million KSc	*#*	*#*	*Million KSc*	*Million KSc*	*Million KSc*
Active Scenario >>			1.363,2	1,62	2,74	6.165,1	18.785,6	(975,8)
	9%	+4,0%	1.373,0	1,62	2,60	6.131,0	18.769,2	(975,8)
	8%	+3,0%	1.384,8	1,63	2,47	6.093,4	18.752,8	(975,8)
	7%	+2,0%	1.398,8	1,63	2,35	6.051,7	18.736,4	(975,8)
	6%	+1,0%	1.415,4	1,63	2,24	6.005,3	18.719,9	(975,8)
Base Case Scenario >>	5%	0%	1.434,9	1,63	2,14	5.953,4	18.703,4	(975,8)
	4%	-1,0%	1.457,9	1,63	2,04	5.895,1	18.686,9	(975,8)
	3%	-2,0%	1.485,0	1,63	1,96	5.829,2	18.670,4	(975,8)

Source: Own elaboration based on Ken-Gen study.

Investment Cost Overrun Factor Sensitivity

		Equity NPV IPP	Minimum ADSCR	Minimum LLCR	Economic NPV Country	Economic NPV Global	NPV Stakeholder
		Million KSc	*#*	*#*	*Million KSc*	*Million KSc*	*Million KSc*
Active Scenario >>		1.363,2	1,62	2,74	6.165,1	18.785,6	(975,8)
	+30,0%	**545,4**	**1,32**	**2,19**	**4.566,9**	**17.642,6**	**(1.074,4)**
	+15,0%	**954,3**	**1,45**	**2,43**	**5.366,0**	**18.214,1**	**(1.025,1)**
Base Case Scenario >>	0%	**1.363,2**	**1,62**	**2,74**	**6.165,1**	**18.785,6**	**(975,8)**
	-5,0%	**1.499,5**	**1,69**	**2,86**	**6.431,4**	**18.976,0**	**(959,4)**
	-10,0%	**1.635,7**	**1,77**	**3,00**	**6.697,8**	**19.166,5**	**(942,9)**

Source: Own elaboration based on Ken-Gen study.

Electricity Tariff Sensitivity

				Equity NPV IPP	Minimum ADSCR	Minimum LLCR	Economic NPV Country	Economic NPV Global	NPV Stakeholder
				Million KSc	#	#	*Million KSc*	*Million KSc*	*Million KSc*
				1.363,2	1,62	2,74	6.165,1	18.785,6	(975,8)
Active Scenario	>>	**165**	+10,0%	**1.889,2**	**1,79**	**3,04**	**7.574,3**	**19.872,3**	**(975,8)**
		158	+5,0%	**1.626,2**	**1,71**	**2,89**	**6.869,7**	**19.328,9**	**(975,8)**
		150	0%	**1.363,2**	**1,62**	**2,74**	**6.165,1**	**18.785,6**	**(975,8)**
Base Case Scenario	>>	**143**	-5,0%	**1.100,1**	**1,54**	**2,58**	**5.460,5**	**18.242,2**	**(975,8)**
		135	-10,0%	**837,1**	**1,45**	**2,43**	**4.755,9**	**17.698,8**	**(975,8)**

Source: Own elaboration based on Ken-Gen study.

Impact of Change in Crude Oil Price

		Equity NPV IPP Million KSc	Economic NPV Country Million KSc
		1.363,2	6.165,1
43	-10,0%	1.325,5	6.048,0
48	0%	1.363,2	6.165,1
53	10,0%	1.400,9	6.282,1
58	20,0%	1.438,6	6.399,2
62	30,0%	1.476,3	6.516,2

Source: Own elaboration based on Ken-Gen study.

10.4 MONTECARLO SIMULATION RISK ANALYSIS

Now that the main variables of risks were identified, the last step of the risk assessment is to model those variables. A Monte Carlo simulation model was constructed (and it is included in the evaluation model), using mainly triangular distribution probability functions. The model assumptions are presented below.

Table 6 - Monte Carlo simulation risk analysis

No. of Iterations	*5.000*
Cost Overrun	
Min	**-50,00%**
Mean	**0,00%**
Max	**100,00%**
Electricity Tariff Sensitivity Factor	
Min	**-5,00%**
Mean	**0,000%**
Max	**5,00%**
Change in Crude Oil Price per Barrel	
Min	**-15,00%**
Mean	**0,000%**
Max	**15,00%**
Domestic Inflation Rate Sensitivity	
Min	**2,00%**
Mean	**5,00%**
Max	**10,00%**

Source: Own elaboration based on Ken-Gen study.

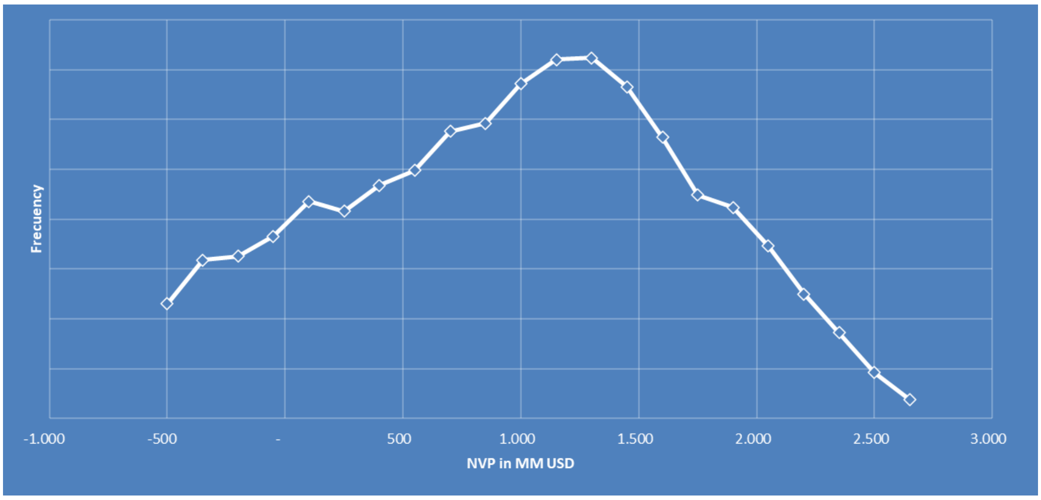
Results of the Monte Carlo simulation shows that the project is very likely to generate a positive NVP both in the private partner that will develop the project and the society due the reduction in oil requirements in order to produce the demanded supply of energy generation.

Table 29 - Monte Carlo simulations NPV

RESULTS	
Positive NVP	**83,48%**
Negative NVP	**16,52%**
Nmean NVP	**$927,99**
NVP Variation	**92%**

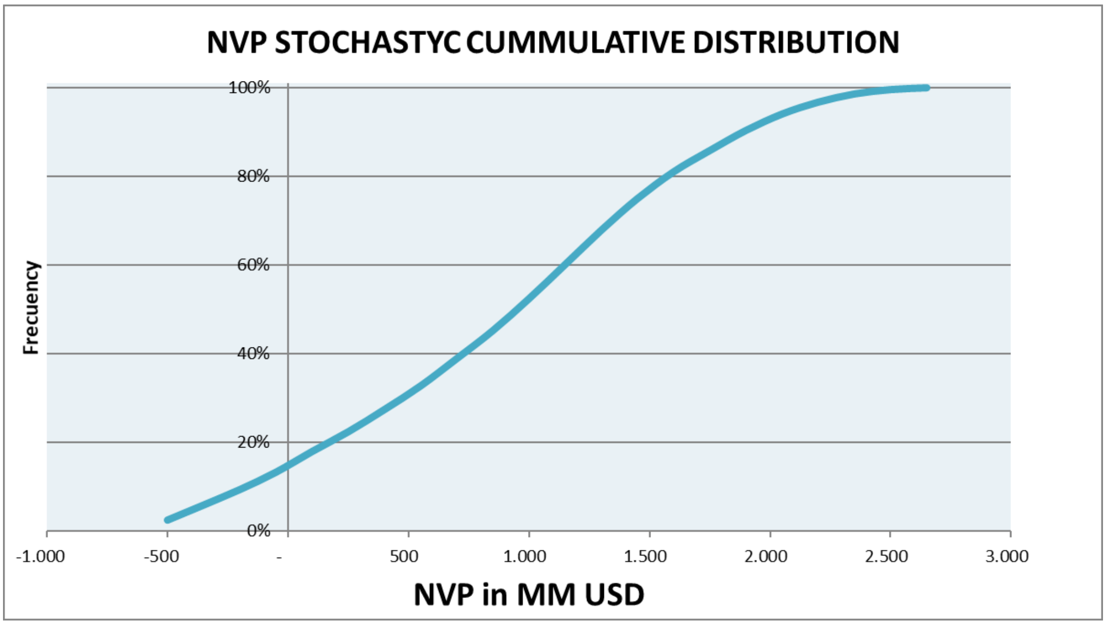
Source: Own elaboration based on Ken-Gen study.

Figure 15 - NVP Stochastic Distribution



Source: Own elaboration based on Ken-Gen study.

Figure 16 - NVP Stochastic acumulative distribution



Source: Own elaboration based on Ken-Gen study.

The analysis shows that the probability of having a positive NVP of this project is 83,48%, even considering some strong assumptions in the risk variables, as a more likely cost overrun scenario and a high expected domestic inflation. Those results indicate an extremely healthy project's perspective.

11 ENVIROMENTAL AND SOCIAL ANALYSIS

Impact on Clean Energy Generation in Kenya

An economic and technical analysis and conceptual design study was conducted for the Seven Forks Solar Project. This analysis included assessing the solar resource, establishing a conceptual plant design and technical specification, and using the results to model an estimatedannual energy production for the Project in a typical meteorological year.

Clean Energy Generation from Seven Forks Solar Project

The Study was initially based on a 10MWac solar project with the possibility of scaling to a higher capacity. During the Project kick-off meetings, KenGen considered the available land area and economics (including likelihood of a high voltage grid interconnection) and concluded that it would be more attractive to target a Project size of up to 40MWac.

Based on KenGen's input and work performed as part of Task #2, the Consultant established a Project capacity and estimated annual energy generation, as summarized in Table below:

Table 30: Seven Forks Solar Project

DESCRIPTION	VALUE
DC Capacity	47.5 MW
AC Capacity	40.0 MW (at point of interconnection)
Generation	97,219 MWh/Year

Source: Own elaboration based on Ken-Gen study.

KenGen's current generation capacity is dominated by hydroelectric and geothermal power and the Seven Forks Solar project would be the first utility scale Solar PV project implemented by KenGen. As KenGen aims to increase its generation capacity to 2,500 MW by 2025 from its currentcapacity of 1,631 MW, this PV solar project will enable the company to simultaneously grow anddiversify its portfolio.

Environmental Impacts

The Project's environmental impacts were quantified by estimating the amount of CO_2, NOX, SOX and CO avoided by reducing generation from fossil fuel fired plants. The quantity of fossil fuel generation displaced by the Project was calculated based on the Project's energy production and the average daily load and generation in Kenya. The amount of CO_2, NOX, SOX, and CO avoided were calculated by multiplying the fossil fuel generation displaced, by theemission factors for each of these chemicals—as reported by the U.S. Environmental Protection Agency.

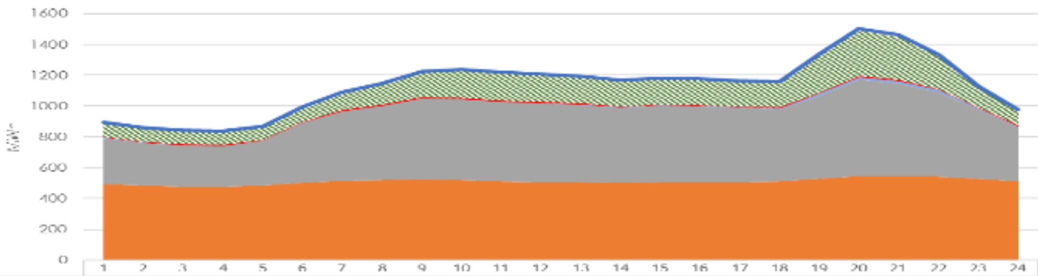
Daily generation with Seven Forks Solar Project

The annual average hourly load and generation profile for Kenya in below figure shows that geothermal generation acts as the country's primary baseload power resource with hydroelectricresources providing intermediate power. The system starts peaking after 6pm and reaches maximum demand around 8pm.

Solar power is an intermittent resource producing energy only during sun hours. The bottom part of Figure 7 shows that the Seven Forks Solar Project starts producing at 6am, reaches peak production around 1pm, and stops producing at 6pm in the evening. The estimated average dailygeneration of the Seven Forks Project is 267 MWh. Given that solar has a lower marginal cost thanHFO/Diesel, it would be less costly to dispatch the solar plant before the HFO/Diesel plants, or alternatively to reduce the hydroelectric generation (to save water) while the solar plant is generating and release the stored water to generate more hydro during the peak hours thereby displacing HFO/Diesel generation. The effect of water storage is increased as the hydroelectric facilities run in a cascade of five plants. A come of water stored in Masinga (the most upstream station) would generate in Masinga and then Kamburu, Gitaru, Kindaruma and finally Kiambere (the most downstream station). As solar and wind generation increases in Kenya, flexible operationof hydroelectric facilities will be crucial in supporting intermittent output from these facilities.

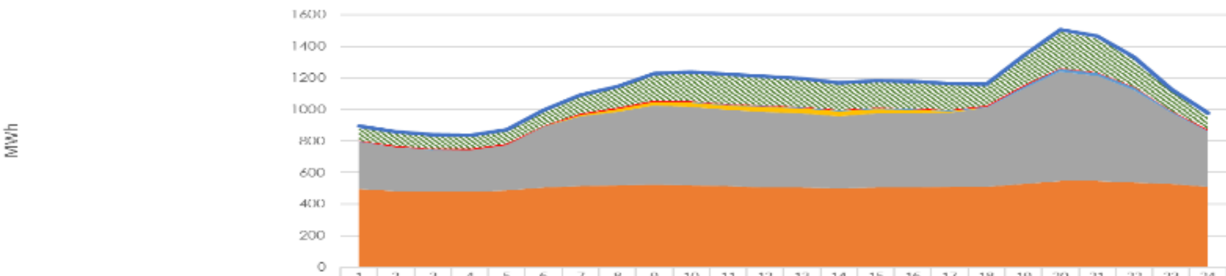
The net effect of both approaches will be the same as HFO/Diesel generation will be displaced bythe amount of solar generation. The information presented in Figure 7 assumes that water will be stored while solar is generating and then released to displace HFO/Diesel during peak hours. Based on this analysis, approximately **267 MWh** of HFO/Diesel generation would be displaced dailyand approximately **97.62 GWh** of Diesel/HFO generation would be displaced annually.

Figure 20: Average Annual Hourly Load Without and With Solar



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Daily HFO/Diesel Generation	94	90	88	88	89	96	116	136	169	182	182	180	175	167	166	165	162	165	244	296	281	214	133	102
Wind	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Imports	3	2	2	2	1	1	0	1	1	2	2	3	4	6	4	4	4	6	15	18	19	16	6	4
Hydro	298	276	266	264	287	388	451	483	526	527	515	509	502	484	496	491	480	467	535	628	600	550	453	352
Geothermal	495	483	478	477	487	504	516	520	522	518	512	507	505	503	505	506	508	511	528	544	544	539	528	511
Annual Average Hourly Load	896	858	841	837	870	995	1090	1147	1227	1238	1221	1209	1196	1170	1181	1176	1165	1160	1340	1505	1463	1334	1129	976

Hours



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
HFO/Diesel (capacity reduced during peak)	94	90	88	88	89	96	116	136	169	182	182	180	175	167	166	165	162	132	178	229	214	181	133	102
Wind	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Imports	3	2	2	2	1	1	0	1	1	2	2	3	4	6	4	4	4	6	15	18	19	16	6	4
Seven Forks Solar	0	0	0	0	0	0	9	19	24	29	31	33	32	30	26	22	11	0	0	0	0	0	0	0
Hydro (saved cap. Added during peak)	298	276	266	264	287	387	442	463	502	498	483	477	470	454	470	468	469	500	602	694	667	583	453	352
Geothermal	495	483	478	477	487	504	516	520	522	518	512	507	505	503	505	506	508	511	528	544	544	539	528	511
Annual Average Hourly Load	896	858	841	837	870	995	1090	1147	1227	1238	1221	1209	1196	1170	1181	1176	1165	1160	1340	1505	1463	1334	1129	976

Hours

Source: Own elaboration based on Ken-Gen study.

Avoided Emissions

Avoided emission for CO_2, NOX, SOX, and CO were calculated by multiplying the heat rate for diesel generators (assumed to be 8000 Btu/KWh) by the emission factors[33] for diesel fuel. The results are summarized in the following table.

Table 31: Avoided Emissions

DESCRIPTION	EMISSION FACTORS (KG/MMBTU)	HEAT RATE35 (BTU/KWH)	YEARLY GENERATION DISPLACED (GWH)	AMOUNT (METRIC TONS)
CO2 avoided	73.32	8,000	97.62	57,257
NOX avoided	2.00	8,000	97.62	1,565
SOX avoided	0.13	8,000	97.62	103
CO avoided	0.43	8,000	97.62	337

Source: Own elaboration based on Ken-Gen study.

Job Opportunities and Human Capacity Building

Another important aspect of the project is its impact on employment in Kenya. This Project would create i) temporary jobs during construction and ii) permanent full-time jobs during operation. Solar PV projects of this size create a significant amount of jobs during the construction phase. Althoughpermanent job creation associated with the operation phase is lower than that for conventional generation technologies, there is potential for indirect yet associated business growth (with less reliance on foreign labour) as solar generation becomes a larger part of Kenya's generation portfolio. Such business areas should include operation and maintenance services, spare parts supply, panel cleaning, vegetation management, data acquisition and monitoring systems, and security.

Job Creation

The total number of labour hours for the Seven Forks project was estimated using labour hours estimates published by the U.S. National Renewable Energy Laboratory (NREL). The results of the calculation are presented below.

Table 32: Calculation of Total Labour Hours for Seven Forks Solar Project

DESCRIPTION	LOW CASE	BASE CASE	HIGH CASE
Skilled Labour Content Hrs/KWdc	0.633	0.844	1.055
Total Skilled Labour	30,086	40,115	50,144
General Labour Content Hrs/KWdc	0.139	0.185	0.231
Total General Labour	6,607	8,793	10,979
Total Labour Hours	36,693	48,908	61,124
Contingency for lost labour hours (25%)	9,173	12,227	15,281
Total Labour Hours Incl. Contingency	45,866	61,135	76,404
Hours Worked Daily	8	8	8
Total Construction Days	200	200	200
Total Full Time Employment Generated	29	38	48

Source: Own elaboration based on Ken-Gen study.

It should be noted that the above numbers are estimates for the U.S. market and represent an average employment number during construction. A contingency component was included to reflect a potential productivity variance from U.S. rates. Actual employment during project construction would fluctuate depending on the labour intensity of the tasks performed e.g. the project would employ more people during the civil construction phase which is more labour intensive and less people during the electrical and instrumentation phase of the project. It is expected a number of around 200 people to be employed during civil construction phase of the project.

In our experience, Solar PV plants require very few full-time employees for operation and maintenance. Based on our assumption, total full-time employment for this project are shown un below table.

Table 33: Full-time Employment during Operations

DESCRIPTION	QUANTITY
Plant Operator	1
General Maintenance	1
Security and Administration	3
Total Operation Jobs	5

Source: Own elaboration based on Ken-Gen study.

Human Capacity Building and Technology Transfer

Since this is KenGen's first solar project, there will be considerable opportunity for the developmentof capabilities and experience in solar PV technology. The confidence gained through successfulexecution this project would encourage increased investment in Kenya and the region.

The following activities will support KenGen's efforts to build internal skill-sets in the area of PV solar development and operation.

12 IMPLEMENTATION PLAN

As a part of the project was prepared a detailed Project Implementation Plan and a Project timeline. As part of the Implementation Plan, it is recommended that KenGen secure an Owner's Engineer to support KenGen during the EPC tender process and construction phase anda financial consultant for lender selection, due diligence and negotiation.

The Project implementation period (i.e. from Study completion to COD) is expected to be approximately 96 weeks and is divided into six phases. These phases are presented in chronological order but include some overlap and interaction between the EPC Tender Process, PPA Negotiations, and Limited Notice to Proceed (LNTP). Table below describes the Project implementation process with key milestones and dates.

Table 34: Project Implementation Phases

PHASE	START DATE (WEEK OF)	END DATE (WEEK OF)	KEY MILESTONES AND APPROVALS	DURATION	NOTES
Phase 1: Initial Development	Mar 3, 18	Mar 3, 18	• KenGen Project Development andESIA Approval • Inclusion in the MasterPlan	8 weeks	
Phase 2: Lender	Mar 10, 18	Dec 27, 18	• KenGen LenderApproval • KenGen approval of Proposed PPA Tariff and Terms • Finalize PPA	32 weeks	• PPA finalization depends on the inputfrom EPC bids and negotiations, which overlap with Phase 2.
Phase 3: EPC Process	Mar 17, 18	Jan 31, 18	• KenGen Approval tostart the EPC Process • Finalize EPC Documentation	34 weeks	• Phase 3 begins one week after the commencement of Phase 2 and is performed concurrently and provides key inputs toPPA negotiations
Phase 4: Financial Closeand Notice to Proceed	Nov 29, 18	Feb 7, 19	• Issue Limited Notice to Proceed (LNTP) • KenGen approval toissue Notice to Proceed	11 weeks	• LNTP is issued in week40, before the EPC process is concluded

Phase 5: Construction and Commissioning	Dec 13, 18	Jan 2, 20	• Perform LNTP Scope • KenGen approval ofBasic Design • Commercial Operation Date	56 weeks	
Phase 6: Post Commissioning	Jan 9, 20	Jan 1, 23	• Energy PerformanceTest	3 years	

Source: Own elaboration based on Ken-Gen study.

12.1 PHASE 1: INITIAL DEVELOPMENT PHASE

The KenGen decision to proceed with full Project development will occur[43] after completion of theStudy and receipt of ESIA approval from the National Environmental Management Authority ("NEMA"). After reaching these milestones, KenGen will start its internal approval process to authorize the development team to move forward with full development of the Project. Once KenGen decides to move forward with the Project, it will present the Project to the Ministry of Energy and Petroleum (MOEP) for inclusion in the Master Plan. CONSULTANT TEAM also recommends that KenGen conduct initial discussions with (and shortlisting of) prospective lenders during Phase 1 to be prepared for lender selection and negotiations in Phase 2.

12.2 PHASE 2: LENDER AND PPA NEGOTIATIONS

Phase 2 begins after MOEP approves the Project's inclusion in the Master Plan. Phase 2 is divided into two sub parts: Lender Selection and Due Diligence and PPA Negotiations

- **Lender Selection and Due Diligence**

CONSULTANT TEAM recommends that KenGen engage an experienced financial consultant to support the lender selection and due diligence process. A financial consultant can provide the necessary financial, legal, and technical support to KenGen during this phase as well as the negotiation of financing documentation during Phase 4.

12.3 PHASE 3: EPC TENDER PROCESS

The EPC tender documents are based on a combination of World Bank guidelines and K&M's experience managing international tender processes. The tender process is a two-stage process with a bidder qualification phase preceding the main tender activities. The summary of key stepsin the EPC tender process is provided below.

12.4 PHASE 4: FINANCIAL CLOSE AND NOTICE TO PROCEED

This phase is comprised of finalizing any pending lender due diligence items and financing documentation, achieving any conditions precedent to financial close, and obtaining

KenGen's internal approval to issue Notice To Procede. Phase 4 is expected to take11 weeks to complete.

12.5PHASE 5: CONSTRUCTION AND COMMISSIONING

Phase 5 consists of the following three steps:

- Pre-Construction: Pre-construction activities include performing LNTP scope, EPC design, procurement, site preparation, review of EPC basic design, and KenGen approval of Final EPC basic design.
- Construction: Construction will begin after the approval of EPC basic design by KenGen. Construction is estimated to take 40 weeks.
- Commissioning and Testing Activities: These include the implementation of relevant commissioning and testing regimes (based on the technical specifications in the EPC contract) and the turnover of the applicable interconnection facilities to KPLC. The Commercial Operation Date (COD) of the Project is January 2, 2022.

The main criteria for successful Project implementation during construction includes, i) achieving Project COD on time and on or under budget, ii) demonstration that all performance guaranteesare met, and iv) demonstration that the Project will be capable of operating consistent with target reliability and availability parameters. Phase 6: Post-Construction

Post-construction activities include a 12-month Energy Performance Test, monitoring of 3-year O&M contractor operation, and post year 3 O&M contractor extension/replacement or conversion to a KenGen self-operate model.