



Massachusetts Institute of Technology
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ESD Working Paper Series

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Prospects for grid-connected solar PV in Kenya: A simulated economic and operational feasibility study

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Abstract

This paper analyzes the economic and technical potential for grid-connected solar PV in Kenya. A unit commitment model is used to evaluate the feasibility of grid-connected solar PV under different price and hydrological conditions in the years 2012 and 2017. In the model, Kenya's extensive reservoir hydro system compensates for daily and seasonal solar intermittency, eliminating the need for investment in battery or other storage capacity. Results show that in the 2012 system the economic value per kW installed of high penetrations of solar PV is greater than the expected revenue under the existing Kenyan feed-in-tariff. This is because solar displaces more expensive fixed and leased fuel oil generation. Evaluation of solar PV under three possible generation mix and demand scenarios in 2017 reveals that the value of solar remains above revenues from the offered feed-in-tariff only if planned investments in low-cost geothermal, imported hydro, and wind power are delayed. The paper focuses on solar investment and no attempt has been made to estimate the theoretical optimal mix. We do not take into account differences in transmission investment associated with different types of generation, which seem likely to favor solar PV in most planning scenarios, nor do we assign monetary value to avoided carbon emissions. The methodology can also be used to estimate the potential for solar and other renewable deployment in many other African countries whose generation capacity is reservoir hydro dominated, or where baseload capacity is provided by costly fossil fuels such as diesel, kerosene, or liquefied natural gas.

Keywords

Solar PV

Renewable integration

Cost of electricity

Kenya

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1. Introduction

With only 1.6 GW of nameplate generating capacity, the Kenyan grid is chronically undersupplied. Investments in new generation capacity have just managed to keep pace with a demand growth of 7% per year (EIA, 2012; IEA, 2012a), leaving no marginal capacity in cases of unplanned plant outages or reductions in hydropower output during droughts. In order to provide some measure of marginal capacity, the Kenyan system operator relies on a combination of fixed and leased diesel at a typical wholesale cost in the range of 0.26 to 0.42 \$/kWh (Kenya Power, 2012). Spurred by rapid demand growth, and faced with a mandate to increase electricity access rates from less than 25% in 2010 (IEA, 2010) to 40% by 2030 (RoK, 2007), system planners must significantly increase generating capacity in the coming years. Plans for new generation capacity are focused on large geothermal and conventional thermal coal and gas projects. While these technologies offer a lower-cost alternative to leased diesel, they have long lead times and require large upfront capital investments in generation and transmission infrastructure, both of which have contributed to the current capacity shortfalls (RoK, 2011a).

Straddling the equator, Kenya receives a significant amount of solar radiation. Figure 1 shows the average daily global horizontal insolation (GHI), which is a measure of total radiation received on a surface from direct and diffuse light of interest for solar photovoltaic (PV) applications. The total estimated generating potential from solar PV nationwide totals over 4,500 TWh per day, exceeding by orders of magnitude the annual consumption of grid-connected electricity, which was 7,627 GWh in 2012 (Kenya Power, 2012).

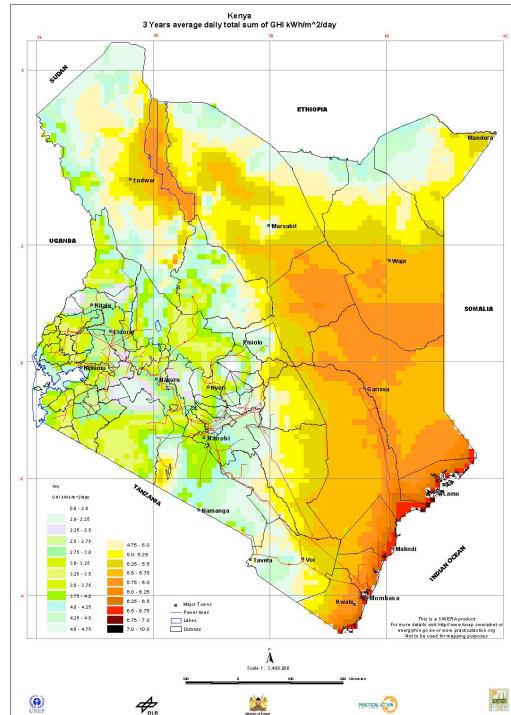


Figure 1 Average daily GHI (kWh/m²/day) from hourly ground-based measurements collected from 2000-2002 (SWERA, 2008)

Despite Kenya’s abundant solar resource, solar PV has been adopted mainly for small off-grid applications (e.g., solar lanterns and solar home systems) due to its relatively high capital costs (RoK, 2011b). However, recent declines in solar module prices combined with sustained high liquid fuel prices are increasingly making large-scale grid-connected solar PV economically competitive with diesel and kerosene fueled generators (Bazilian et al., 2012). In practical terms, the extent to which grid-connected solar PV could be introduced depends on the temporal overlap of demand and solar output and the amount of energy storage available on the grid to mitigate any mismatch.

Kenya has extensive reservoir hydropower capacity, accounting for almost 50% of total installed capacity. This could be operated in such a way as to compensate for diurnal fluctuations in solar output, thereby eliminating the need for additional investments in storage (IEA, 2012b). Additionally, shorter construction times for solar PV installations provide a hedge for system planners against load growth uncertainty. In this paper, we evaluate the economically feasible limits of grid-connected solar PV in Kenya in the years 2012 and 2017. We identify and evaluate the impacts of PV penetration on cycling of thermal generators, fossil fuel consumption and instances of unmet demand. Finally, we evaluate the potential for solar PV to eliminate the need for leased diesel capacity in the 2012 system, and for new coal and diesel capacity in year 2017 under different scenarios.

The remainder of the paper is organized as follows. Section 2 provides an overview of previous work. Section 3 contains the model methodology and description followed by a presentation of results in Section 4. A discussion of the results is provided in Section 5 and final conclusions are offered in Section 6.

2. Previous Work

The global solar PV market has been growing rapidly, spurred by reduced cell prices, increased manufacturing capacity and more aggressive policies on the part of many governments to promote renewable energy. Annual growth in installed PV capacity has averaged over 52% in the last decade, from 636 MW in 2000 to an estimated 98,000 MW in 2012 (GlobalData, 2012). Europe is the world's leader with over 70% of the total global installed capacity. Installations in Africa and the Middle East, by contrast, make up only 0.36% of the total (GlobalData, 2012).

Previous feasibility studies of solar PV on the electric grid have focused on the US and European markets, while little attention has been paid to developing countries. The barriers to incorporating intermittent renewables can vary significantly from a power system with full electricity access and low demand growth such as in the US, to a system where a significant fraction of the people lack access to electricity and demand grows briskly, as is the case of many developing countries. In mature US power systems, Denholm and Margolis (2007) and Zahedi (2011) find that solar PV penetration is limited by the ramping constraints of existing generators and the need to match intermittent generation and demand. In developing countries, where electric power systems are not mature, planners have the opportunity to adopt flexible generation assets and network infrastructure capable of supporting intermittent generation sources from the outset.

Added storage, in the form of pumped hydro or batteries, has been suggested to smooth ramping rates and improve the response to power system disturbances (Esmaili and Nasiri, 2009). However, none of the studies reviewed have assessed the limits of solar PV penetration for systems in which large amounts of storage potential in the form of reservoir hydropower already exists. In such power systems, PV penetration may be limited now by economic rather than technical constraints. Studies on solar PV in sub-Saharan Africa tend to focus on rural electrification and off-grid applications rather than grid-connected projects (Krause and Nordstrom, 2004). Two notable exceptions are feasibility studies of PV plants in South Africa by de Groot et al. (2013) and net-metered rooftop PV in Kenya by Hille and Franz (2011).

Some attempts have been made to assess the economic competitiveness of solar PV in various markets. Levelized cost of energy (LCOE) comparisons were used by Reichelstein and Yorston (2013) and Breyer et al (2010) to examine the competitiveness of solar PV in US and Middle East and North Africa regions, respectively. Reichelstein and Yorston (2013) found that utility-scale solar PV plants were not cost competitive with coal or natural gas plants in the US, while Breyer et

al. (2010) found that rooftop PV systems are already competitive with such plants in some regions of MENA. Reichelstein and Yorston (2013) also used a comparison of solar PV LCOE values with retail electricity rates to determine if commercial-scale solar PV has achieved “grid parity” in various regions in the US. The results differed by location due to variations geography, solar resources and subsidy schemes. Recently Ondraczek (2013) used a LCOE comparison to estimate the cost of solar PV in Kenya and found that solar PV is already competitive with some traditional fossil fuel plants currently in use.

A shortcoming of LCOE comparisons is that they treat different generation types independently, ignoring their interactions with other generators within a particular power system. For example, solar PV may be more valuable in circumstances when it displaces expensive peaking capacity, typically provided by diesel, kerosene or natural gas. The penetration level of the candidate technology can also affect its added value: overly high penetration levels may cause less costly technologies to be curtailed or ramped extensively, increasing the system-wide costs of energy. LCOE values – which are independent of temporal or operational relationships in the system – do not capture these system-level costs and benefits. As with LCOE comparisons, grid parity assessments fail to account for the potential added value that a candidate technology could provide to the power system as a whole. Additionally, it potentially compounds other tariff elements, such as fuel subsidies, into the comparison that reflect policy decisions instead of the true cost of generation.

Interest in assessing the potential use of reservoir hydropower to compensate for diurnal and seasonal fluctuations in solar generation is relatively new (IEA, 2012b) and existing planning tools used in Kenya and other African countries are typically not designed for this purpose. Further, commonly used capacity expansion tools, such as WASP, use LCOE and other technology specific tools such as screening curves (RoK, 2011a) to estimate the least cost generation mix. Such an analysis is not appropriate for solar and wind technologies, which are best evaluated from a system perspective. Currently in Kenya, long-term plans are made using multiple models including VALORAGUA and WASP (RoK, 2011a). In addition to using cost comparisons that do not take the existing generation mix into account, both tools lack the hourly time-scale required to evaluate the coincidence of solar generation with demand patterns (IAEA, 1992; IAEA, 2006).

For the reasons outlined above, a new approach and suitable computation tools are needed to assess the technical and economic feasibility of adding solar PV onto the Kenyan grid. The study is thus designed to address four key questions: What are the savings in operating cost that result from added solar PV capacity to the Kenyan system? Given these savings, what is the economic value per kW installed of the solar PV investment? How do these savings compare with expected revenues based on Kenya’s FIT and FITs seen in comparable markets in India and South Africa? How do these results change under different 2017 growth scenarios?

3. Methodology

3.1 Data and Case Studies

We used four data sets to represent the Kenyan generation assets available in 2012 and three possible generation mixes in 2017 (Table 1). National plans to expand and diversify the generation mix are based on ambitious goals to more than double current generating capacity by 2017. Given the high degree of uncertainty that all of these investments will be completed as scheduled, two alternative 2017 scenarios were used to reflect cases where projects are delayed and demand growth is slower than anticipated.

These scenarios are:

1. **2012**: all plant and demand data reflect conditions as reported in 2012 by the system operator;
2. **2017 National Plan (NP)**: generation mix and demand projections based on government plans published in the Least Cost Power Development Plan (RoK, 2011a);
3. **2017 Geo High**: demand based on historic annual growth rate of 7% and only planned investments in hydro and geothermal are achieved;
4. **2017 Geo Low**: demand based on historic annual growth rate of 7%, half of planned geothermal investments are completed and the remaining demand is met through increased diesel capacity.

| Generator Type | 2012 | 2017 | | |
|--------------------------|---------------|---------------|---------------|---------------|
| | | National Plan | Geo High | Geo Low |
| Hydro | 733.2 | 765.2 | 765.2 | 765.2 |
| Geothermal | 202.0 | 1060.3 | 1060.3 | 631.2 |
| Gas Turbine (Kerosene) | 60.0 | 0 | - | - |
| Diesel | 455.8 | 796.8 | 455.8 | 885.0 |
| Cogeneration (Bagasse) | 26.0 | 26.0 | 26.0 | 26.0 |
| Emergency Power (Diesel) | 120.0 | - | - | - |
| Coal | - | 600.0 | - | - |
| Wind | - | 435.5 | - | - |
| Imports | - | 600.0 | - | - |
| Total Capacity | 1597.0 | 4283.8 | 2307.3 | 2307.4 |

Table 1 Installed generation capacity in 2012 and 2017 simulated years (MW) (RoK, 2011a).

Table 2 contains the operating parameters for each generator type. The maximum capacity of each plant is reduced to reflect power consumed for the plant's own use,

auxiliary load factor, as well as periods when the plants are unavailable due to planned or unplanned outages, *outage rate*.

| Generator Type | Outage Rate | Aux. Load Factor | Ramp Rate [GW/h] | Fuel Consumption | | |
|----------------|-------------|------------------|------------------|-------------------|--------------|--------------|
| | | | | Variable [MJ/kWh] | Fixed [MJ/h] | Start Up [J] |
| Diesel | 0.902 | 0.94 | 0.12 | 7.66 | 0.008 | 0.084 |
| Kerosene GT | 0.922 | 0.94 | 0.12 | 11.47 | 0.004 | 0.084 |
| Geothermal | 0.932 | 1 | 0.005 | - | - | - |
| Cogeneration | 1 | 0.98 | 0.13 | 41.83 | 0.042 | 0.042 |
| Hydro | 0.903 | 1 | - | - | - | - |
| Coal | 0.733 | 0.9 | 0.6 | 9.92 | 0.008 | 0.017 |
| Wind | 1 | 1 | - | - | - | - |
| Imports | 0.85 | 1 | - | - | - | - |

Table 2 Operating parameter assumptions for each generation technology (RoK, 2011a Parness, 2011 RoSA, 2010 Mumias, 2012).

Table 3 contains the assumed costs of fuel, operation and maintenance, leasing, and investment for each generator type. Leasing costs are only applied to the diesel capacity provided by emergency power producers in the 2012 system and investment costs are only applied to new plants included in the 2017 scenarios.

| Generator Type | Fuel Cost [\$/GJ] | | Variable O&M [\$/MWh] | Annual fixed O&M [\$/kW] | Annual fixed Investment [\$/kW] | Lease [\$/GW] |
|----------------|-------------------|------|-----------------------|--------------------------|---------------------------------|---------------|
| | 2012 | 2017 | | | | |
| Diesel | 16.9 | 14.6 | 9.0 | 62.5 | 176.6 | 40.8 |
| Kerosene GT | 19.4 | - | 12.0 | 11.8 | - | - |
| Geothermal | - | - | 5.57 | 56.0 | 461 | - |
| Cogeneration | 5.3 | 5.3 | 9.0 | 11.8 | - | - |
| Hydro | - | - | 0.0 | 21.3 | 533.8 | - |
| Coal | - | 3.4 | 4.3 | 69.0 | 359.7 | - |
| Wind | - | - | 0.0 | 28.1 | 288.3 | - |
| Imports | - | - | 5.0 | 29.6 | 60.3 | - |

Table 3 Variable and fixed cost assumptions for each generation technology (RoK, 2011a IEA, 2012c IEA, 2012d).

Hourly demand values in 2012 are based on actual loads experienced during the period July 2011 – June 2012 (Kiano, 2012a). Kenya experiences a fairly stable load during the year with minimal seasonal variation and peak demand in the evenings

(Figure 2). A factor of 13% was added to the hourly load values to account for high rates of transmission and distribution losses.

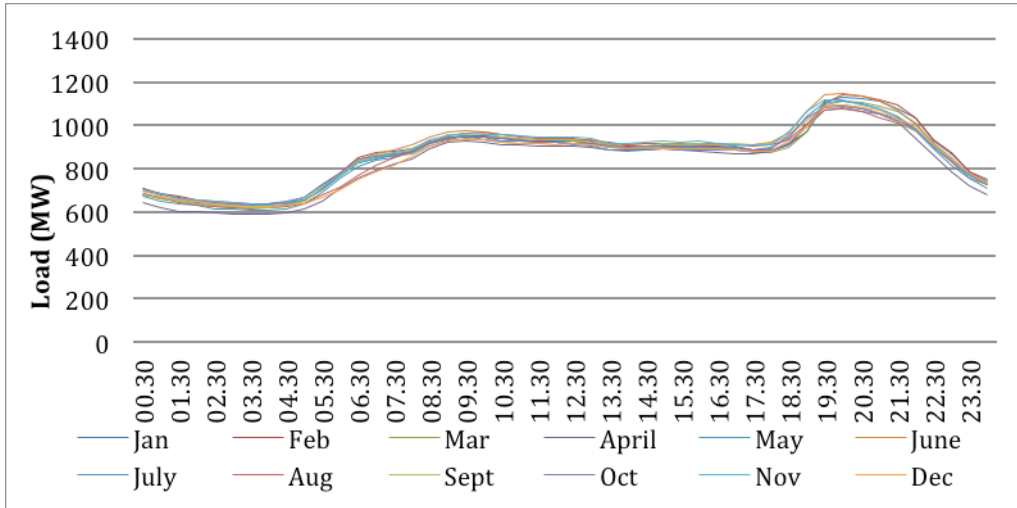


Figure 2 Monthly sampling of Kenya's hourly demand curve (Kiano, 2012a).

The Government of Kenya uses end-use electricity models to forecast peak demand to 2031 (RoK, 2011a). Based on these forecasts, the peak demand in the 2017 National Plan scenario will reach 3,230 MW, reflecting a very high annual growth rate of 18%. Projected demand in the Geo High and Geo Low scenarios, by contrast, is based on the continued historic growth rate of 7% annually, resulting in lower projected peak demand of 1,743 MW in 2017. Hourly load curves for all 2017 scenarios are generated by multiplying the 2012 loads by the ratio of 2017 and 2012 peak demand. This method does not account for future shifts in consumption patterns that may change the shape of the daily demand profile. Based on historical reductions in network losses and national goals to improve these rates, 2017 network losses are predicted to fall to 11% and total load values are increased by the new loss factor to reflect the need for additional generation.

In our calculation, we used historic data over the period of 1948-1994 to estimate the variations in annual inflows and the effects of inter-annual inflow relationship (e.g., a dry year followed by a dry year) (Kiano, 2012b). The solutions obtained for each simulated year are averaged to represent an *average* hydrological year. A cumulative distribution function of the total annual inflows for each year in the data set was used to characterize *dry* and *wet* hydrological years. The solutions from years in the lowest 20th percentile of annual inflows from the dataset were averaged to represent a typical *dry* year. Similarly, a typical wet year was calculated from solutions obtained for years in the highest 20th percentile.

Ground-based hourly time series measurements of global horizontal insolation (GHI) from 23 measuring stations collected over 2000-2002 were used to represent the solar resource in Kenya (SWERA, 2008). Hourly radiation values were based on the average from all sites over the 3-year measuring period. A shortcoming of this methodology is that values averaged over multiple years and multiple locations tend

to mask variability and uncertainty in estimated solar generation. We do not consider this to be significant in this study, given the built-in storage capacity of the Kenyan power system.

The projected power system in the 2017 National Plan includes a significant increase in wind generation from four proposed plants. Hourly output from wind plants is conventionally calculated using a power curve, specific to each turbine, to convert wind speed to power generation. Unfortunately, hourly time series data are not available for the proposed plant sites and the conventional approach could not be used. Though wind generators can experience significant daily and seasonal fluctuations in output, wind output in this model is assumed to be constant in every hour based on annual production estimates found in project design documents for each plant (Faupel et al., 2011; Theuri and Oludhe, 2008; Yoshida, 2012). As with solar, we assume that existing hydro storage capability renders wind intermittency insignificant for the objectives of this study. As interest in wind generation in Kenya grows, additional wind resource data may become available, providing greater accuracy in future studies.

For each simulated year, eleven scenarios were run: one base case with no solar, referred to as the 0 PV case, and ten solar scenarios with installed PV capacity ranging from 100 to 1000 MW.

3.2 Electric Power System Model

A unit commitment model of the Kenyan system was used to obtain a cost-minimizing hourly schedule for each generating unit over the simulated year. The model can be run in two modes: expansion planning and unit commitment. In the 2012 system, all investment decisions have been made, and the model was run in unit commitment mode only. The objective function of the unit commitment model is formulated as the sum of annual fixed costs, variable operation and maintenance costs, fuel costs, and penalties for non-served power. The unit commitment schedule is subject to constraints pertaining to the minimum operating requirements and ramp rates of each generating unit, minimum reservoir volumes that must be maintained in each month, requirements that supply must meet demand and spinning reserve levels in every period.

The 2017 simulations involve both expansion planning and unit commitment decisions. For this initial assessment, we only evaluated the potential for solar PV to decrease planned investments in coal and medium speed diesel plants. Therefore, the expansion planning model was only applied in the National Plan and Geo Low scenarios where use of these two technologies is expected to grow. The expansion planning model introduces new decision variables to represent the capacity of the plants. For each capacity value of the candidate technologies, the unit commitment subproblem generates an hourly schedule. The multiplication of two decision variables (i.e. capacity of candidate technology and unit commitment decision of that technology) creates a non-linear problem. In order to maintain linearity, the “Big M”

method is introduced to encompass the new capacity decision variables as a series of inequality constraints.

Further information on the model mathematical formulations and the Big M methodology can be found in (Rose, 2013; Griva et al., 2009). This work was done with the General Algebraic Modeling System (GAMS) and solved as a mixed integer linear problem using the CPLEX interior point method.

3.3 Economic Analysis

The economic value of adding solar PV to the Kenyan system was determined based on the impact on the total annual production cost. The addition of an intermittent renewable technology to an existing power system imposes multiple impacts on production costs, both positive and negative. Increased generation from renewable sources may displace production from traditional fossil fuel plants resulting in savings from reduced fuel consumption. On the other hand, intermittent renewables may impose additional operating costs for other plants that must ramp up and down more frequently to accommodate changes in output from the intermittent source (Hargreaves and Hobbs, 2012). For this analysis, the total system cost was calculated as the operation cost of generation plus the annual fixed cost of each non-solar generator.

The maximum annual savings from added solar PV in each scenario is the difference in the total system production cost with respect to the 0 PV case in the year 2012. A 20 years lifetime and 5% discount rate have been assumed when computing the annuities of any capital costs. Another static analysis has been done also for the year 2017. The economic value (\$/W) of the investment for the considered year was calculated by dividing the expected annual savings of the plant by its size.

In order to compare these results with what is currently achievable in Kenya and similar developing markets, the annual revenues that could be earned based on the Kenyan feed-in-tariff and project prices bid in India and South Africa were calculated. These revenues were expanded using the same lifetime and discount rate assumptions mentioned above to estimate the total expected revenue over the lifetime of the plant and investment costs per W installed. From an investor's point of view, they are interested in a solar project only if the estimated revenue from the feed-in-tariff is greater than their expected investment cost. The comparisons with actual projects being achieved in India and South Africa can provide an indication as to whether the investment costs are achievable.

We will focus on the comparison of expected savings and expected revenues from the Kenyan feed-in-tariff. These results provide insight as to whether the feed-in-tariff is well-adjusted and, if so, the economically feasible limits of PV penetration. If the revenues from the feed-in-tariff exceed the expected system-wide savings, investment in solar PV at that penetration level is not economical for the consumers, as they must pay the cost of the support scheme. If, however, the expected savings

exceed the cost of the feed-in-tariff, the consumers benefit from the corresponding solar penetration. Here it is left open whether the existing feed-in-tariffs are high enough to attract investment in solar PV, which directly depends on the solar investment and operation costs.

4. Results

4.1 Effect of solar PV in the 2012 power system

4.1.1 System operations

Figure 3 and Figure 4 show the generation profiles of a sample week in the 2012 0PV and 500 MW scenarios, respectively. The majority of demand in the 0 PV scenario is met through hydropower and fuel oil plants. As solar capacity is introduced to the system, the model optimizes to reduce total production from the most expensive plants and minimizes additional ramping and start up costs.

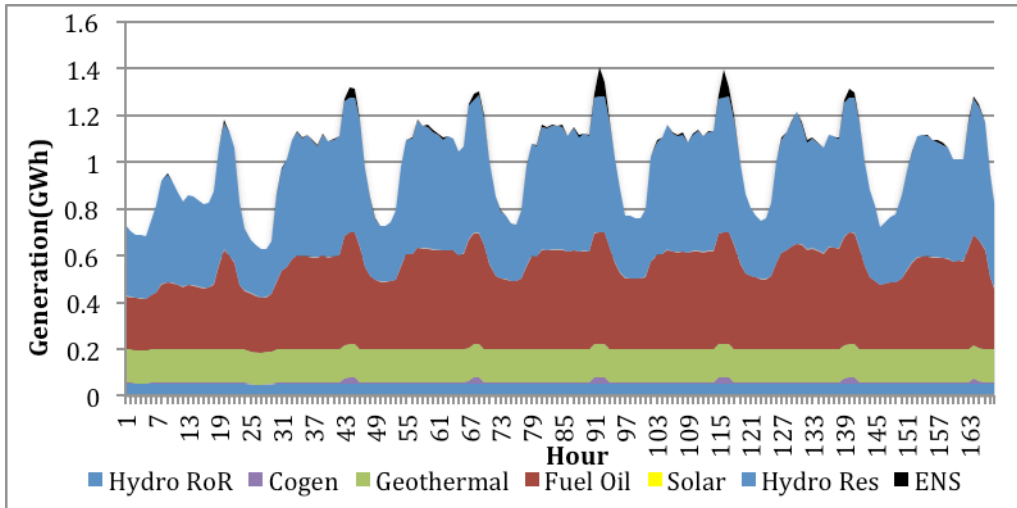


Figure 3 Hourly generation profile in the 2012 0 PV scenario.

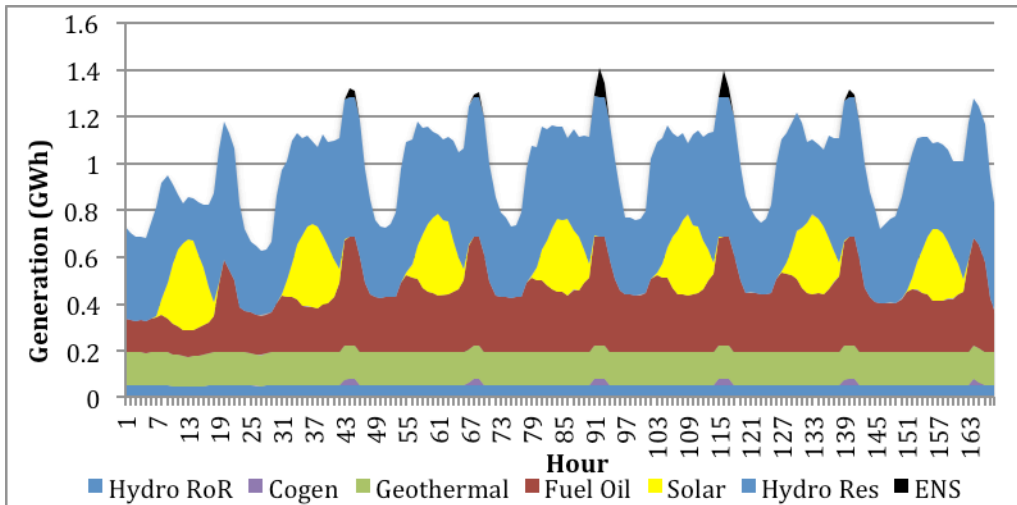


Figure 4 Hourly generation profile in the 2012 500 MW solar PV scenario.

As Figure 5 shows, generation from fuel oil plants is displaced during the day by solar generation and during the evening by increased hydro generation. Production during the day from fuel oil plants is reduced mostly due to their high variable costs. During the evening, further reductions in output would require the plant to shut down for brief periods, increasing the costs of the system. Thus, the output from reservoir hydropower plants is reduced to avoid additional startup costs of fuel oil plants, capitalizing on the ability of these hydro plants to alter their output while maintaining total generation levels and avoiding cost penalties (Figure 5).

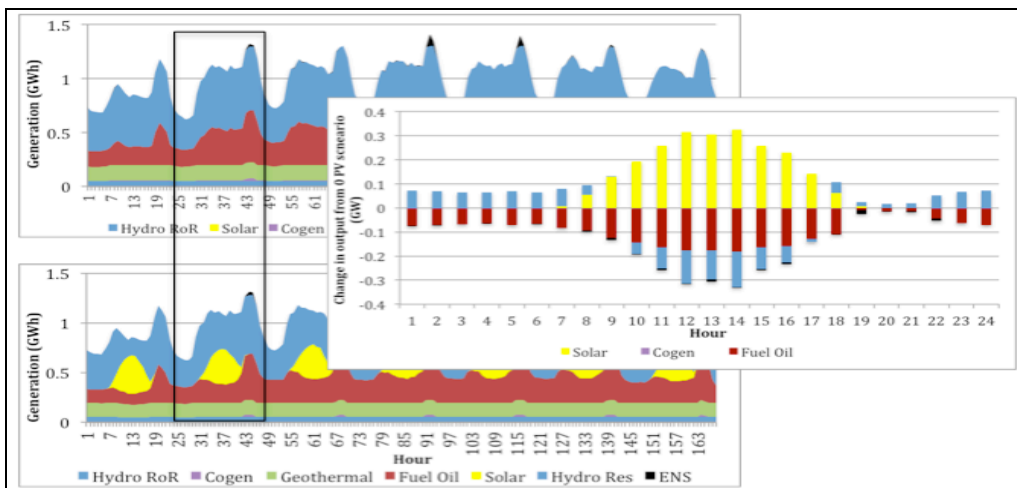


Figure 5 Changes in generation as a result of 500 MW solar penetration over a sample 24-hour period in the 2012 scenario. Generation from diesel is displaced by solar generation during the day and by shifted hydropower generation during the evenings and night.

A key result to note is the incidence of unmet demand during peak hours on some days (represented as “energy non-served”, ENS). For a small number of hours, around 250 in the 0 PV scenario, there is insufficient capacity to meet demand over the simulated year. This value is consistent with the 238 load shedding events recorded during the same period by the Kenyan system operator (Kiano, E., 2012c). The shape of Kenya’s demand curve, with peak demand during the evening hours,

limits the ability of solar PV to contribute directly to shave the peak and reduce instances of unmet demand. For reservoir hydropower plants, reduced daytime generation allows these plants to shift their generation to evening hours reducing some instances of unmet demand during early evenings when hydro plants were not previously maximizing their output (since they were strictly needed to also avoid unmet energy at other times).

Finally, Figure 6 contains the comparison of total annual generation by technology for each scenario in the 2012 simulated year. Added solar production in this scenario results in reduced generation from fuel oil plants.

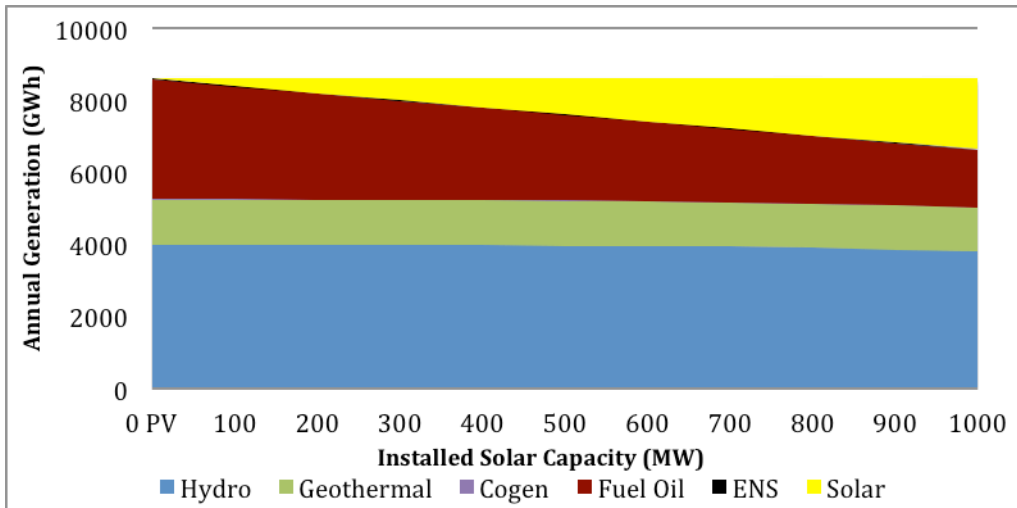


Figure 6 Annual generation output by technology under different solar scenarios in the 2012 system

4.1.2 Total system costs

In 2012, reductions in system production costs for different levels of solar penetration are largely the result of reduced fuel consumption in fuel oil plants. Figure 7 shows the maximum investment cost (breaking even, with no economic losses because of solar penetration) that a solar plant could incur based on the reduced cost of generation from other generating units. The first trend that emerges from this analysis is that solar PV displaces the most expensive generation technologies first, thus the investment value of solar PV falls as the installed capacity increases. Second, the value of solar PV investment is highest in dry hydrological conditions when more production from fuel oil plants is required to compensate for reduced hydropower generation.

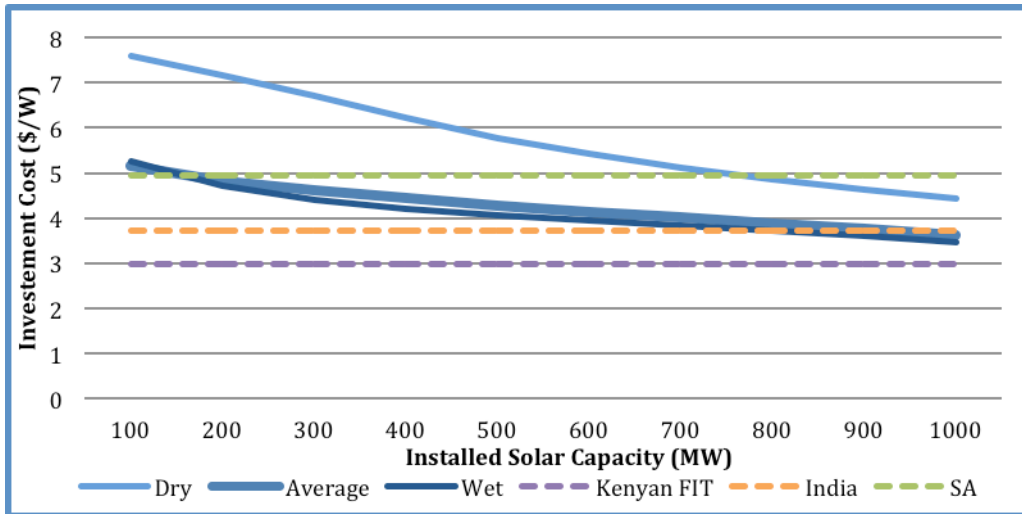


Figure 7 Value of solar PV investment at different penetration levels in the 2012 simulated year compared with expected revenues from remuneration schemes in Kenya, India and South Africa (SA).

As the figure shows, the maximum solar PV investments that are economically justified by the production cost savings fall from \$5.1 to \$3.6 per W in an average year, as penetration levels increase from 0 to 1000 MW. In the dry year scenario, possible payment levels increase further to \$7.6 to \$4.4 per W due to increased displacement of expensive generation from fuel oil plants by solar PV production. For all hydro scenarios and penetration levels, these maximum investment values are higher than the per W costs that would have been obtained from the current feed-in-tariff for grid-connected solar PV in Kenya (RoK, 2012), indicating that the investment is economical for Kenyan consumers. Based on this information, if the Kenyan feed-in-tariff should happen to be insufficient to attract solar PV investment, it could be set at a higher value for some penetration levels without increasing operating costs. There are no major grid-connected solar PV projects currently operating in Kenya, and it is yet to be seen if the present tariff rate is sufficient to attract new projects. Further comparisons with prices achieved through auctions in South Africa and India, \$0.20 per kWh and \$0.15 per kWh, respectively, (Gowrishankar, 2013, Oirere, 2012) reveal that up to 200 MW of solar PV could be economically feasible at bid prices experienced in South Africa, and up to 900 MW for the prices experienced in India[†]. Of course, the savings in system production costs in these countries will be different from those calculated for Kenya. For an additional reference point, the average cost of private solar PV projects in least developed countries is \$3 per W (WB, 2013). The calculated values remain above this level for all hydro scenarios and penetration levels, further indicating that high levels of solar penetration may be economically justified in Kenya.

4.2 Effect of solar PV in the 2017 power system

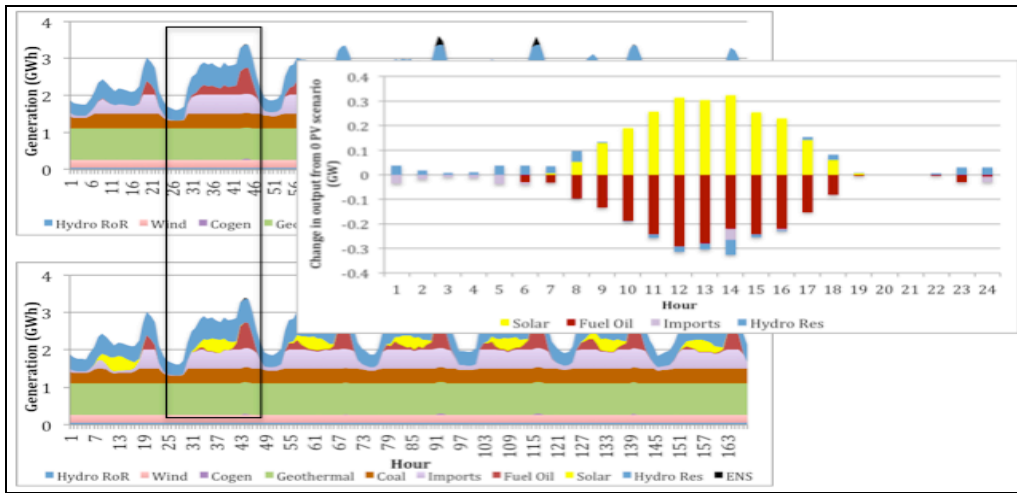
4.2.1 System operations

[†] Ondraczek (2013) estimates the LCOE for PV in Kenya is \$0.21 per kWh.

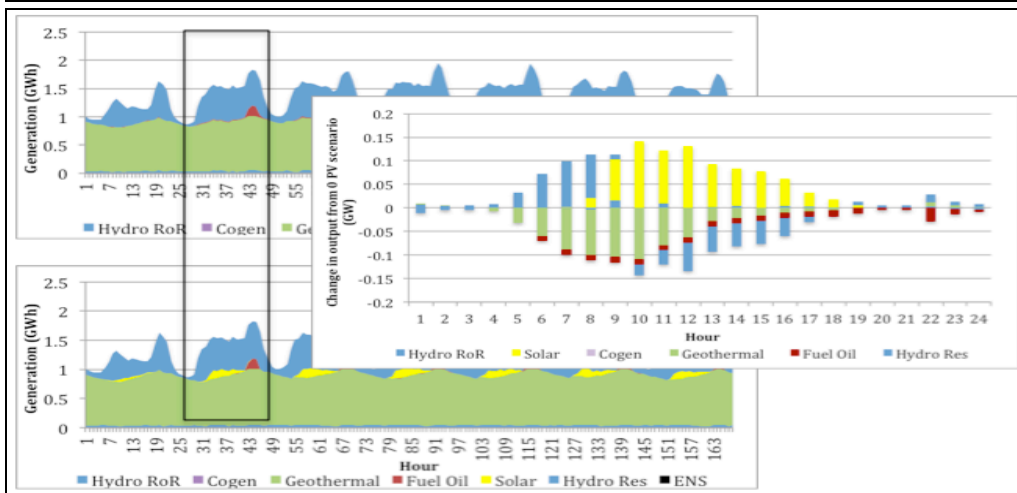
Under the **2017 National Plan** scenario (Figure 8a), as solar is added to the system daytime production from fuel oil plants is reduced as compared to the no PV case. Higher levels of solar penetration result in reductions from coal and imported sources. Since hydropower production is already maximized during peak periods, there is no possibility of shifting hydro production from daytime to evening hours. The addition of solar PV production during the day does not contribute to reducing evening demand and therefore instances of unmet demand persist during peak hours. As a result, the optimized level of new coal and diesel capacity built remained unchanged for each level of solar penetration.

Under the **2017 Geo High** scenario (Figure 8b), increased generating capacity from geothermal plants eliminates the need for diesel production in all but peak periods. Therefore, only small levels of diesel generation are displaced by added solar PV capacity. The high level of inflexible geothermal capacity limits the opportunity for solar PV in this system. Geothermal plants, with slow ramping rates, cannot significantly decrease their output during the day to accommodate solar generation because they are needed to operate at maximum capacity in order to meet peak demand in the evenings. As a result, solar is curtailed during the day in order to keep the geothermal plants running, despite the economic advantage of solar power. In the 100 MW scenario 35% of solar generation is curtailed. This value increases to 75% in the 1000 MW scenario. Notably, output from geothermal plants must be ramped down during the day to accommodate hours of low demand even in the 0 PV scenario. This mode of operation is highly inefficient and unlikely to be permitted in a real system, indicating that the level of inflexible geothermal capacity may be too high for the level of demand represented in this scenario.

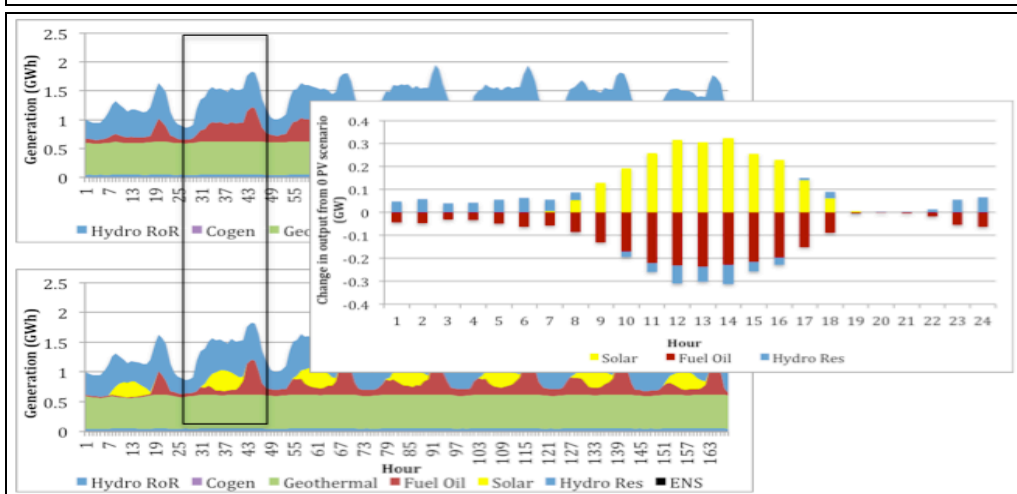
Finally, the **2017 Geo Low** scenario (Figure 8c) reflects a more realistic generation mix as it avoids the need to reduce output from the geothermal plants seen in the 2017 Geo High scenario. As in the 2012 case, diesel generation is still used to meet significant portions of demand under this scenario. As a result, added solar capacity displaces diesel output directly during the day and indirectly in the evenings through shifted reservoir hydropower production. The optimized level of new diesel capacity remained the same for all solar scenarios because these plants were required to meet peak demand during the evenings. For this, and the 2017 National Plan, only with additional hydro storage capacity, or if the shape of the future demand curve were to change such that peak demand corresponds with solar production could added solar capacity potentially reduce the need for these plants.



(a)



(b)



(c)

Figure 8 Changes in generation output as a result of 500 MW solar penetration over a sample 24-hour period in the 2017 a.) National Plan, b.) Geo High, and c.) Geo Low scenarios.

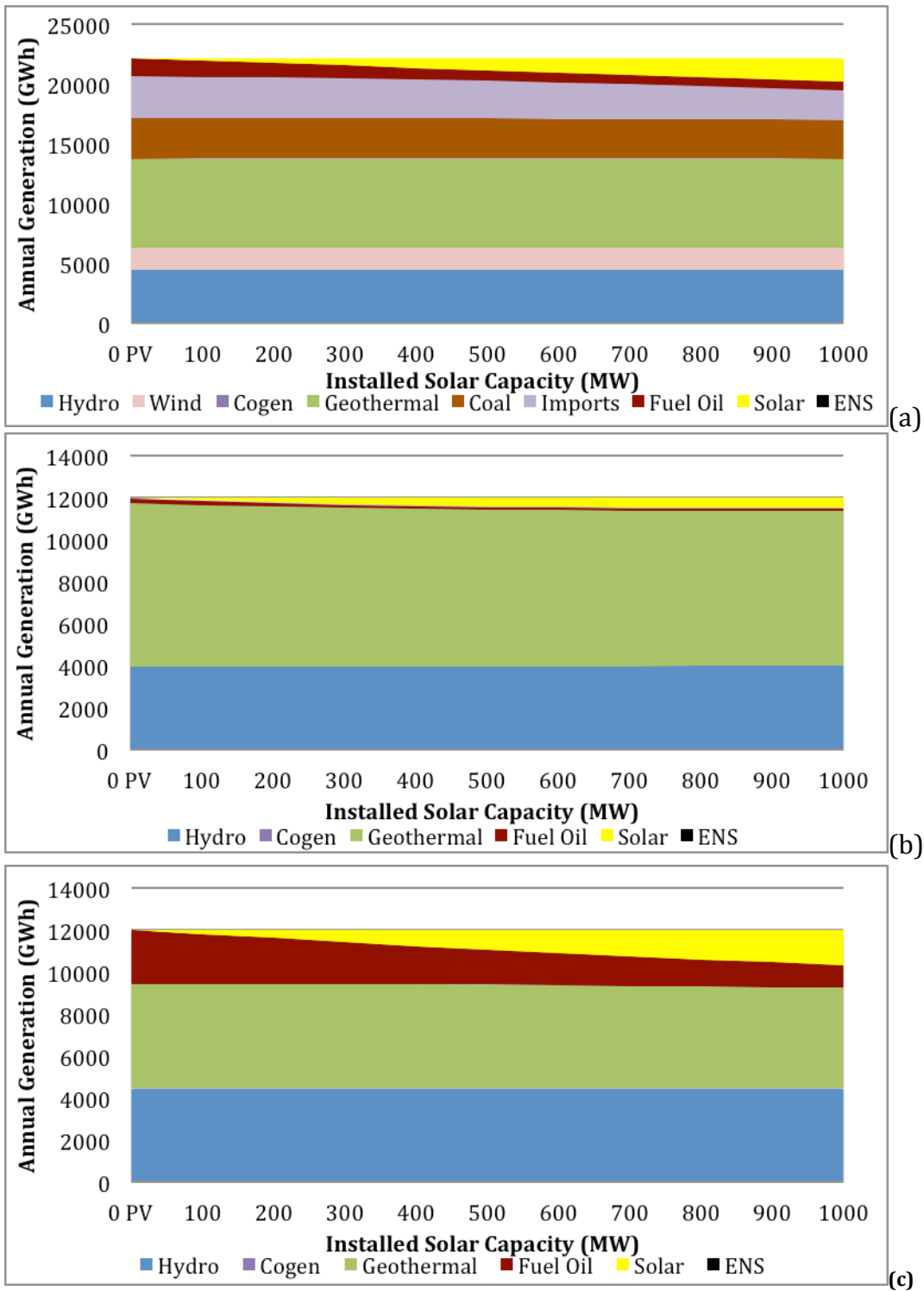


Figure 9 Annual generation output by technology for each solar PV scenario in the 2017 a.) National Plan, b.) Geo High, and c.) Geo Low scenarios. In the National Plan and Geo High scenarios, there is limited generation from diesel plants to be curtailed resulting in displaced generation from less expensive sources such as geothermal, coal, imported and domestic hydropower. In Geo High scenario, large portions of solar generation must be curtailed to due the high levels of inflexible geothermal capacity.

4.2.2 Total system costs

For the **2017 National Plan** (Figure 10), the production cost analysis of added solar PV in the 2017 system reveals a range of investment values of \$2.7 to \$1.9 per W. For all scenarios, these values are significantly less than those found for the 2012 scenario. This is due to expected changes in the generation mix between 2012 and 2017. The increased use of low variable cost technologies such as geothermal, coal, and wind and the low utilization of fuel oil plants eliminate the potential economic gains from displacing production from costly thermal generation with solar PV. Savings from added solar capacity are not sufficient to cover the cost of solar PV investment in any hydrological scenario under the current feed-in-tariff in Kenya and the rates in South Africa and India.

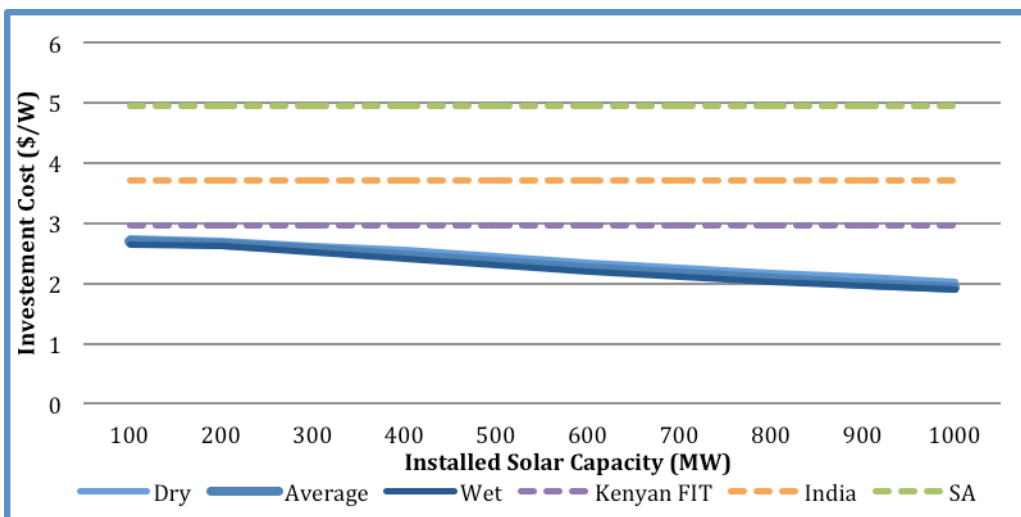


Figure 10 Value of solar PV investment at all penetration levels in the 2017 simulated year fall below investment costs based on revenues from tariffs in Kenya, India, and South Africa (SA).

As in the National Plan scenario, the **2017 Geo High** (Figure 11) generation mix contains limited opportunities to displace generation from diesel plants with solar generation. As a result, large portions of solar generation must be curtailed to avoid displacing generation from preexisting hydropower plants. The production cost analysis reveals a range of investment values of \$1 to \$0.2 per W. These rates fall below the investment cost based on expected revenues from the Kenyan feed-in-tariff and rates in India and South Africa, as in the 2017 National Plan scenario. Unlike the 2012 and National Plan scenarios where limited or no curtailment of solar generation resulted in steady investment costs for each assumed revenue rate, the heavy curtailment of solar production in this scenario results in falling maximum investment costs based on revenues as well as production cost savings.

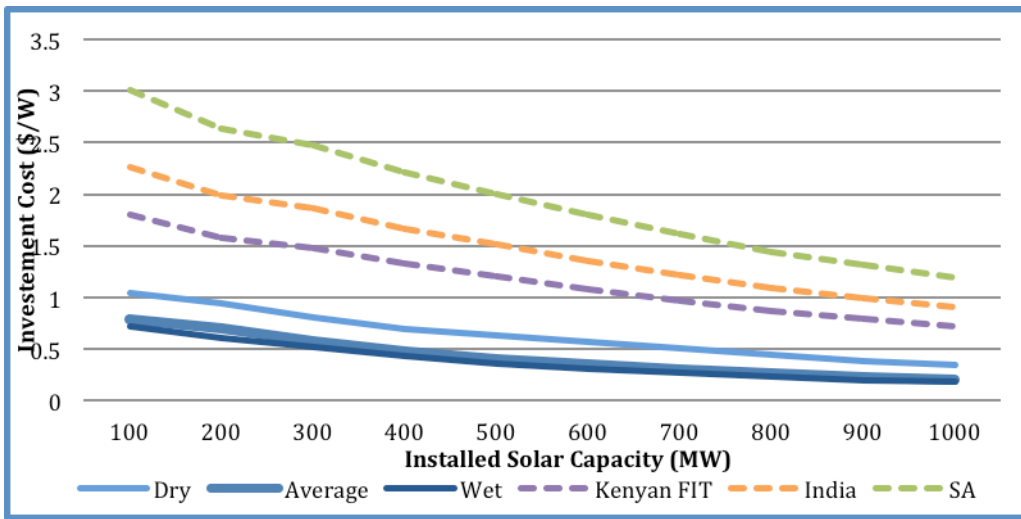


Figure 11 Heavy curtailment of solar generation in the 2017 Geo High simulated year results in values of solar PV investment at all penetration levels below those based on remuneration schemes in Kenya, India, and South Africa (SA).

Finally, continued use of diesel generators in the **2017 Geo Low scenario** (Figure 12) provides an economic opportunity for solar PV to displace output from these plants. While added solar output displaces diesel generation almost exclusively in each solar scenario, the savings from reduced fuel consumption are lower than those seen in the 2012 simulated year because the most expensive kerosene-fueled plants have been decommissioned by this time. The resulting range of investment values is \$3.4 to \$2.4 per W. Based on these values, up to 500 MW of solar PV would be economically justified based on revenues from the Kenyan FIT. These rates, though not achievable based on expected revenues from current project prices in India or South Africa, may prove feasible in 2017 if PV project prices continue to decrease. Total solar production is curtailed at higher penetration levels, as evidenced by the falling investment cost curves based on expected revenues.

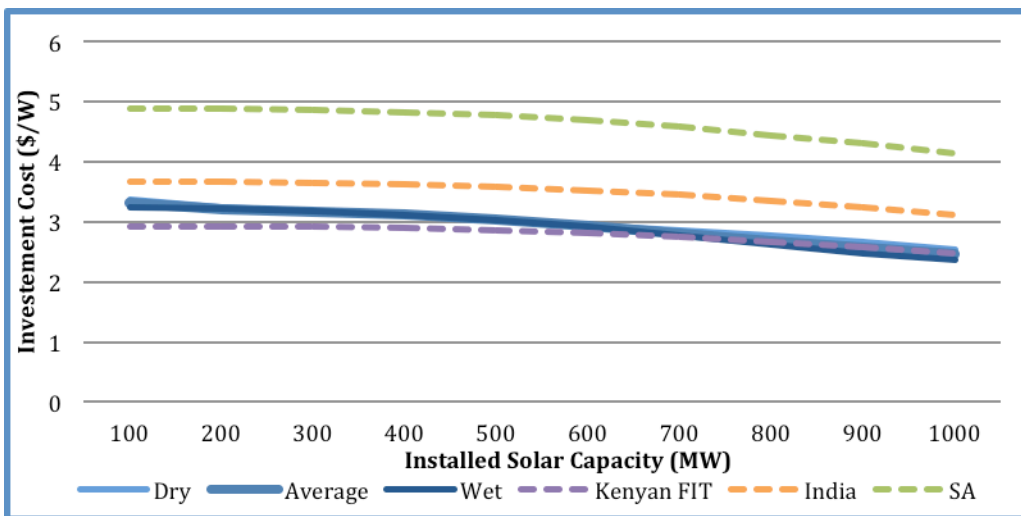


Figure 12 Value of solar PV investment in the 2017 Geo Low simulated year indicate high levels of PV investment would be justified only at rates comparable to the Kenyan FIT.

5. Discussion

Solar PV may offer an economic alternative to the current use of power from fuel oil plants while at the same time increasing energy security and lowering growth in global CO₂ emissions. Simulations of the current 2012 and potential 2017 systems indicate that Kenya's reservoir hydro capacity could enable the integration of high penetrations of solar PV without the need for additional investments in storage.

There are significant opportunities for PV to displace generation from fuel oil plants, currently providing 38% of Kenya's electricity, with solar PV. Under the existing feed-in-tariff, more than 1000 MW of solar PV capacity could be connected to the Kenyan grid without increasing total system costs. However, this feed-in-tariff may reflect overly optimistic project development costs on the part of the Kenyan policy-makers, as suggested by the fact that no major investments in solar PV have taken place in Kenya so far. At the higher winning values of wholesale bids recently recorded in South Africa and India, the economically justified threshold for PV penetration in Kenya ranges from 100-900 MW.

Under current planning methodologies where technologies are evaluated at an individual project-level using as a crude metric for comparison the levelized cost of each technology, solar PV capital investment costs remain too high to compete with those of coal, geothermal, hydro, and wind power in 2017. However, the system-level approach used in this study shows that investment in solar PV still has an economic value for consumers in 2017 under the current feed-in-tariff. If ambitious plans to decommission the most expensive kerosene units and build significant new capacities of geothermal, coal, and wind power are completed, the economic value of added solar PV will fall below achievable revenues in 2017 under the adopted hypotheses. If, as demonstrated in the more realistic 2017 Geo Low scenario, plans for new plants are delayed and diesel plants are used to fill the capacity gap, solar PV investment ranging from 100-500 MW may continue to be economically justified from the consumers' perspective under the current Kenyan FIT.

The cost of required transmission infrastructure for coal, diesel, and wind plants proposed in the 2017 plans was not included in this analysis. If solar PV could be sited near major load centers, avoiding these transmission investments, the economic competitiveness of solar in the future system would increase. The impact on distribution network costs will depend on the spatial configuration of demand and solar plants. Additionally, the 2017 projected demand profile was based on the 2012 system. Changes in consumption patterns over time that result in a flattening of the demand curve or daytime peaks in demand would tend to favor the economics of solar PV over diesel. Uncertainty in demand growth would also favor solar PV over large-scale projects that require long lead times and supporting infrastructure.

In the near term, solar PV is a feasible alternative to increasing diesel production to meet increasing demand because it can be financed and deployed incrementally and may avoid the need for accompanying investment in transmission infrastructure if it can be sited near major load centers. This is particularly important if large-scale

investments required for new geothermal, coal, wind, and imported power fail to attract investors and are therefore delayed, requiring extended use of fuel oil plants.

While this analysis focused on the potential for solar PV in the Kenyan system, the results may be applicable to other sub-Saharan African countries, many of whom are faced with the same challenges facing the Kenyan system: growing demand for electricity, insufficient generating capacity, long lead times and extensive financial investments required for planned generation projects. As a result, many countries have turned to short-term expensive solutions such as leased emergency power from diesel plants. On the other hand, the characteristics that may make solar PV a favorable option in Kenya – an abundant solar resource, large capacities of untapped reservoir hydropower, and heavy use of costly diesel generators – are also present across the continent. For policy-makers and international organizations eager to reduce carbon emissions and dependence on imported fuels, the deployment of hydro resources alongside intermittent renewables such as hydro and wind may be a viable option. Solar PV may also be attractive in non-hydro based systems where diesel is the primary source of baseload power. For evaluation of the penetration limits of solar PV in any of these systems, a similar analysis can be used that takes into account the particular system configuration.

6. Conclusion

This study was designed to provide a top-level assessment of the feasibility of grid-connected solar PV in the Kenyan power system and the adequacy of the present Kenyan feed-in-tariff support scheme. A unit commitment and expansion-planning model simulates system operations in the 2012 and projected 2017 systems to determine the technical and economic implications of added solar PV capacity. Results show that the economic value of high levels of solar PV in the 2012 system is greater than expected revenues based on the national FIT or comparable prices achieved in South Africa and India due to savings from avoided production from fuel oil plants. Under current planning scenarios, extensive investments in geothermal, wind, and coal capacity drastically reduce the economic gains of added solar PV capacity by 2017. However, the value of solar PV remains above expected revenues from the FIT in 2017 if these projects are delayed, resulting in continued use of diesel generators.

The use of a multi-nodal model that includes transmission and distribution networks in future work could increase the accuracy of calculated gains or costs of introducing solar PV in Kenya as well as provide insights as to what geographic and capacity constraints the existing network may impose on potential project sites. Additionally, additional storage capacity could increase the economic case for solar PV by shifting generation to match evening peak hours. Further work on the value of storage in the Kenyan system may result in expansion planning scenarios that incrementally increase reservoir hydro and solar PV capacity in a coordinated fashion or favor concentrated solar power technologies.

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