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WIDER Working Paper 2014/095

Prospects for grid-connected solar photovoltaic in Kenya

A systems approach

Amy Rose¹, Robert J. Stoner², and Ignacio Pérez-Arriaga³

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Abstract: Capacity planners in developing countries frequently use screening curves and other system-independent metrics such as levelized cost of energy to guide investment decisions. This can lead to spurious conclusions when evaluating intermittent power sources such as solar and wind. We use a system-level model for Kenya to evaluate the potential of using grid-connected solar photovoltaic in combination with existing reservoir hydro-power to displace diesel. Different generation mixes are evaluated with a unit commitment model whereby Kenya's extensive reservoir hydro-system compensates for solar intermittency. Results show that the value of high penetrations of solar in 2012 exceeds their potential investment cost. Under three 2017 generation scenarios, the investment value of solar remains high if planned investments in low-cost geothermal, imported hydro, and wind power are delayed. The methodology can be used to estimate renewable potential in other African countries with comparable power generation situations.

Keywords: solar photovoltaic (PV), renewable integration, developing countries

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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 cent per year (EIA 2012; IEA 2012a), leaving no marginal capacity in cases of unplanned plant outages or reductions in hydro-power 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 US\$/kWh (Kenya Power 2012a). Spurred by rapid demand growth, and faced with a mandate to increase electricity access rates from less than 25 per cent in 2010 (IEA 2010) to 40 per cent 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). For countries, such as Kenya, where significant portions of power are currently supplied by diesel generators and less expensive alternatives such as gas or coal require significant investments in supporting infrastructure, solar photovoltaic (PV) could be used to displace a significant amount of fuel oil generation. Shorter construction times for solar PV installations provide a hedge for system planners against load growth uncertainty and the displacement of expensive diesel generation could reduce system-wide generation costs.

Straddling the equator, Kenya receives a significant amount of solar radiation. Global horizontal insolation (GHI), a measure of total radiation received on a surface from direct and diffuse light, is used to gauge the generating potential for solar PV applications. Measurements from ground-based sites collected from 2000-02 estimated the generating potential of solar PV nationwide totals over 4,500 TWh per day (SWERA 2008), exceeding by orders of magnitude the annual consumption of grid-connected electricity, which was 7,627 GWh in 2012 (Kenya Power 2012a).

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 the perception that capital costs remain too high (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-fuelled generators (Bazilian et al. 2012). The current methodologies used to evaluate candidate plants in Kenya's long-term planning strategy do not capture the system-level benefits of added solar PV and, as a result, solar PV is perceived to be too expensive for grid-scale deployment. 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.

Unlike diesel generation, solar PV output is only available for limited parts of the day and cannot be controlled without large investments in energy storage. The need to compensate for fluctuations in solar output with energy storage or backup technologies is a key economic barrier to high penetrations of solar PV. Kenya's existing reservoir hydro-plants, accounting for almost 50 per cent of total capacity, offer a potential low-cost solution to the variability problem. By coordinating hydro-power production to compensate for seasonal and diurnal fluctuations in solar output, high penetrations of solar PV may be achieved without disruptions to energy supply or the need for investments in energy storage (IEA 2012b).

In this paper, we use a system-level model of the Kenyan generation system to calculate the economic value of PV investments in Kenya. We do this for the 2012 reference case, as well as for

the 2017 case under several assumed investment outcomes. Significantly, we include in our model a realistic representation of Kenya’s extensive hydroelectric system, which includes both run-of-river and reservoir-type facilities. This enables us to treat hydroelectric facilities both as generators and energy storage devices, curtailing output when the sun is shining and PV output is high, and increasing in the evening, when PV output is low. With this model we derive the value per watt of PV capacity added to the system over a wide range of total capacities. We then compare our results with expected revenues that could be obtained by the Kenyan feed-in tariff, and bids from recent PV capacity auctions in South Africa and India.

1.1 Previous work

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 in 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 hydro-power already exist. 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 (MENA) 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 USA, 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 USA. The results differed by location due to variations in geography, solar resources, and subsidy schemes. 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 hydro-power 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. Furthermore, commonly used capacity expansion tools, such as the Wien Automatic System Planning (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 VALORAGUA¹ 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 to the Kenyan grid. The study is thus designed to address four key questions: (i) What are the savings in operating cost that result from adding solar PV capacity to the Kenyan system? (ii) Given these savings, what is the economic value per kW installed of the solar PV investment? (iii) How do these savings compare with expected revenues based on Kenya's feed-in tariff (FIT) and FITs seen in comparable markets in India and South Africa? (iv) How do these results change under different 2017 growth scenarios?

2 Materials and methods

2.1 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. Geothermal capacity, for which Kenya, somewhat uniquely, has considerable potential, plays an important role in the 2017 plan. 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: generation mix and demand projections based on government plans published in the Least Cost Power Development Plan (RoK 2011a);

¹ VALORAGUA is a modelling software developed by the International Atomic Energy Agency for the optimal operating strategy of mixed hydrothermal generating systems.

3. 2017 Geo High: demand based on historic annual growth rate and new generation assets only include planned hydro and geothermal investments;
4. 2017 Geo Low: demand based on historic annual growth rate, investments in hydro expansion are completed, half of planned geothermal investments are completed and the remaining demand is met through increased diesel capacity.

Table 1: Installed generation capacity in 2012 and 2017 simulated years (MW)

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

Source: Authors' compilation based on data from 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).

Table 2: Operating parameter assumptions for each generation technology

Generator type	Outage rate	Aux. load factor	Ramp rate (GW/h)	Fuel consumption		Start-up (J)
				Variable (MJ/kWh)	Fixed (MJ/h)	
Diesel	0.098	0.94	0.12	7.66	0.008	0.084
Kerosene GT	0.078	0.94	0.12	11.47	0.004	0.084
Geothermal	0.068	1	0.005	-	-	-
Cogeneration	0	0.98	0.13	41.83	0.042	0.042
Hydro	0.097	1	-	-	-	-
Coal	0.267	0.9	0.6	9.92	0.008	0.017
Wind	0	1	-	-	-	-
Imports	0.15	1	-	-	-	-

Source: Authors' elaboration based on data from 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.

Hourly demand values in 2012 are based on actual loads experienced during the period July 2011–June 2012 (Kenya Power 2012b). Kenya experiences a fairly stable load during the year with minimal seasonal variation and peak demand in the evenings (Figure 1). A factor of 13 per cent was added to the hourly load values to account for experienced rates of transmission and distribution losses (RoK 2011a).

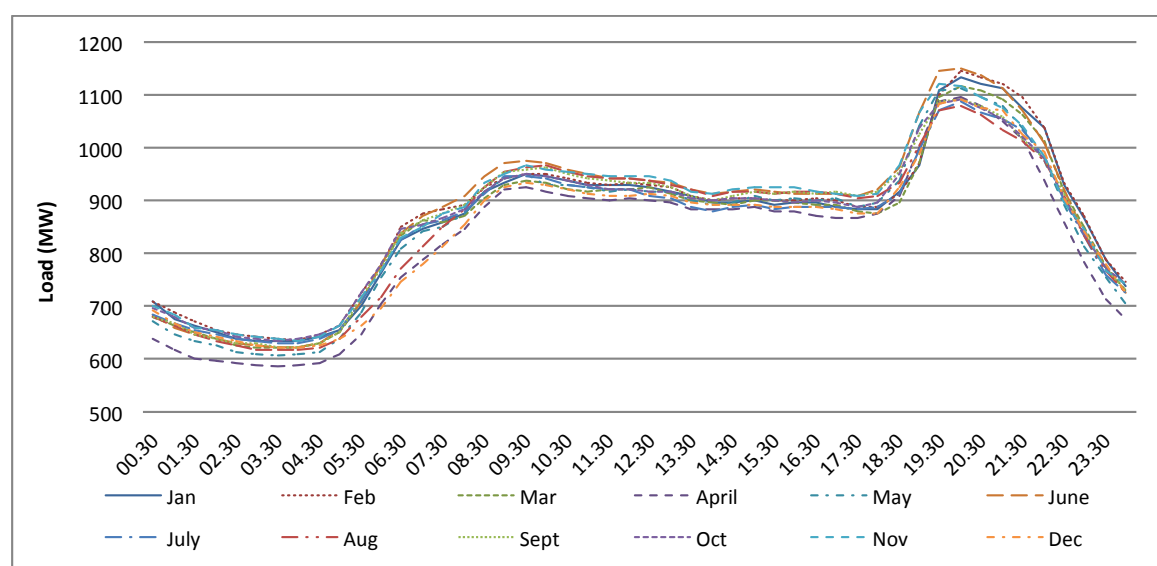
Table 3: Variable and fixed cost assumptions for each generation technology

Generator type	Fuel cost (US\$/GJ)		Variable O&M (US\$/MWh)	Annual fixed O&M (US\$/kW)	Annual fixed Investment (US\$/kW)	Lease (US\$/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	-
Non-served Energy			840			

Note: O&M is operation and maintenance.

Source: Authors' elaboration based on data from RoK (2011a); IEA (2012c); IEA (2012d).

Figure 1: Monthly sampling of Kenya's hourly demand curve



Note: The curve reveals a fairly stable demand during the day with peak demand during the evenings and minimal seasonal variation.

Source: Authors' elaboration based on data from Kenya Power (2012b).

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 almost 20 per cent. Projected demand in the Geo High and Geo Low scenarios, by contrast, is based on the continued historic growth rate of 7 per cent 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 per cent and total load values are increased by the new loss factor to reflect the need for additional generation. The reserve requirement set by the national grid code mandates that the system must be able to meet demand if the two largest units of the system are unavailable (Energy Regulatory Commission 2008). Since we did not have accurate information on the size of individual units for each power plant, this spinning reserve requirement was simplified to equal the capacity of the largest dispatched plant in each period.

For the hydro-power plants, we used historical data over the period of 1948–94 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) (Kenya Power 2012c). We obtained an *average* hydrological year by averaging the solutions obtained for each individually simulated year. Representative *dry* and *wet* hydrological years correspond to solutions from the years with annual inflows in the lowest and highest 20th percentile, respectively. Rule curves for each reservoir were based on information provided by the plant’s owners and production function values were calculated based on recorded production data for each plant.

Ground-based hourly time series measurements of GHI from 23 measuring stations collected over 2000–02 were used to represent the solar resource in Kenya (SWERA 2008). Hourly radiation values were based on the average from all sites over the three-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, 11 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.

2.2 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. Table 4 contains the input parameters and decision variables for the model formulation.

Table 4: Input parameters for unit commitment model

Parameter	Description	Unit
pD	Demand in each period	(GW)
pSpRes	Spinning reserve in each period	(GW)
pCNSE	Cost of non-served energy	(US\$/k/GWh)
pQmax	Maximum output	(GW)
pQmin	Minimum output	(GW)
pOut	Outage rate	(p.u)
Pk	Auxiliary load factor	(p.u)
pO	Variable O&M cost	(US\$/k/GWh)
pFixed	Annual fixed cost	(US\$/M/GW)
pLease	Leasing cost of emergency power	(US\$/M/GW)
pUp	Upward ramping rate	(GW/h)
pDown	Downward ramping rate	(GW/h)
pF	Fuel cost	(US\$/k/Mth)
pAlpha	Variable fuel consumption	(Mth/GWh)
pBeta	Fixed fuel consumption	(Mth/h)
pGamma	Fuel consumption during start up	(Mth)

pResMax	Maximum reservoir volume	(Mm ³)
pResmin	Minimum reservoir volume	(Mm ³)
pInflow	Inflow into reservoir	(Mm ³)
pProdFunc	Production function of hydro-plant	(GWh/Mm ³)
pInsol	Global horizontal insolation	(p.u.)
pPVplant	Capacity of solar PV plant	(GW)
pWind	Wind production	(GWh)

Note: A Mth is an energy unit with 1 thermie (th) = 4.1868 MJ.

Source: Authors' elaboration.

Table 5: Decision variables for unit commitment model

Decision variable	Description	Unit
ENS(p)	Non-served energy in each hour	(GW)
Q(p,g)	Generation from plant g in hour p	(GW)
Commit(p,g)	Binary variable to indicate if a plant is on or off in period p	(1-0)
StartUp(p,g)	Binary variable to indicate a start-up decision	(1-0)
ShutDown(p,g)	Binary variable to indicate a shut-down decision	(0-1)
Fix(g)	Binary variable to indicate if the plant was used during the year	(0-1)
Res(r,p)	Reservoir level in current period p	(Mm ³)
S(r,p)	Water spilled from reservoir	(Mm ³)

Note: The sets p, g, and r represent the sets of hourly periods, generation plants, and reservoirs respectively.

Source: Authors' elaboration.

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 penalties for non-served energy, variable operating and maintenance costs, fuel costs, and annual fixed costs.

$$\begin{aligned}
\text{Minimize } & \sum_p pC_{NSE}ENS(p) \\
& + \left\{ \sum_g pO(g)Q(p,g) \right. \\
& + pF(g)[pBeta(g)Commit(p,g) \\
& + pGamma(g)StartUp(p,g) + pAlpha(g)Q(p,g)] \\
& \left. + Fix(g)[pFixed(g) + pLease(g)] \right\}
\end{aligned} \tag{1}$$

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. These constraints were formulated using the following equations.

Minimum and maximum operating limits

$$Q(g,p) \leq Commit(p,g) * pQmax(g) * pOut(g) * pk(g) \tag{2}$$

$$Q(g,p) \geq Commit(p,g) * pQmin(g) \tag{3}$$

Ramping constraints

$$Q(g, p) - Q(g, p - 1) \leq pUp(g) \quad (4)$$

$$Q(g, p - 1) - Q(g, p) \leq pDown(g) \quad (5)$$

Start-ups and shut-downs

$$Commit(g, p) = Commit(g, p - 1) + StartUp(g, p) - ShutDown(g, p) \quad (6)$$

Hydro-reservoir limits

$$\begin{aligned} Res(r, p) = & Res(r, p - 1) - Q(g, p) + S(g, p) \\ & + pInflow(r, p) \\ & + \sum UpriverPlants \llbracket Q(gup, p) + S(gup, p) \rrbracket \end{aligned} \quad (7)$$

$$pResMin(r, p) \leq Res(r, p) \leq pResMax(r, p) \quad (8)$$

Supply–demand balance

$$\sum_g Q(g, p) + ENS(p) = pD(p) \quad (9)$$

Spinning reserve constraint

$$SpRes(p) = pQmax(g) * Commit(p, g) - Q(g, p) \quad (10)$$

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 a new decision variable, $Cap(g)$, to represent the capacity of the plants. For each candidate technology, the unit commitment model solves for the capacity value and the 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, a series of linear inequality constraints using the dummy variable Y were introduced to relate the unit commitment decision to the capacity decision.

Set Y to 0 if unit is not committed

$$Y(p, g) \leq 1000Commit(p, g) \quad (11)$$

Set the capacity of new unit to 0 if it is not committed

$$-Cap(g) + Y(p, g) \leq 0 \quad (12)$$

Set maximum Y value

$$Cap(g) - Y(p, g) + 1000Commit(p, g) \leq 1000 \quad (13)$$

Set maximum capacity value

$$Cap(g) \leq 1000 \quad (14)$$

The objective function remains the same only the fixed costs now include a fixed investment cost for units that are built in addition to fixed maintenance costs. This work was done with the General Algebraic Modelling System and solved as a mixed integer linear problem using the CPLEX² interior point method.

2.3 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-year lifetime and 5 per cent 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 (US\$/W) of the investment for the considered year was calculated by dividing the expected lifetime savings due to the solar 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 watt 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 carried out in India and South Africa can provide an indication as to whether the investment costs are achievable.

We 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 still an open question whether the existing feed-in tariff is high enough to attract investment in solar PV, which directly depends on the solar investment and operation costs.

² CPLEX is an optimization software package developed by IBM; the name is derived from the simplex algorithm it uses.

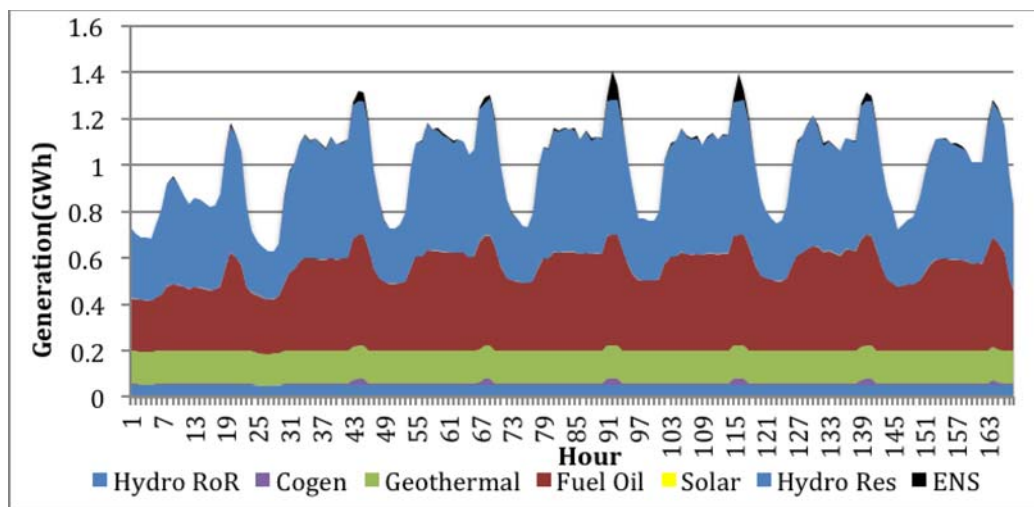
3 Results

3.1 Effect of solar PV in the 2012 power system

System operations

Figure 2 and Figure 3 show the generation profiles of a sample week in the 2012 0 PV and 500 MW scenarios, respectively. The majority of demand in the 0 PV scenario is met through hydro-power and fuel oil plants. As solar capacity is added to the system, the model optimizes to reduce total production from the most expensive plants and minimize additional ramping and start-up costs. This has the effect of displacing total fuel oil output.

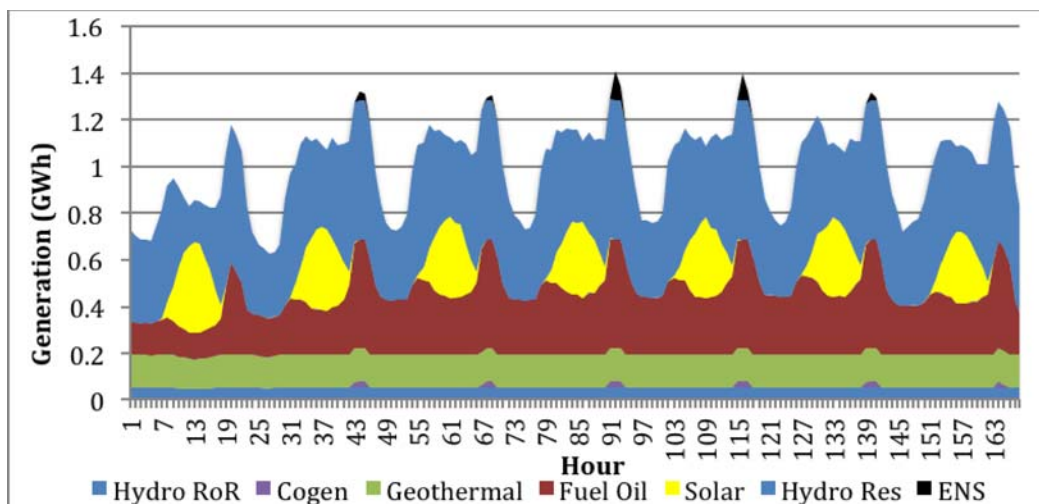
Figure 2: Hourly generation profile in the 2012 0 PV scenario



Note: Most power generation comes from reservoir hydro and fuel oil plants.

Source: Authors' calculations.

Figure 3: Hourly generation profile in the 2012 500 MW solar PV scenario



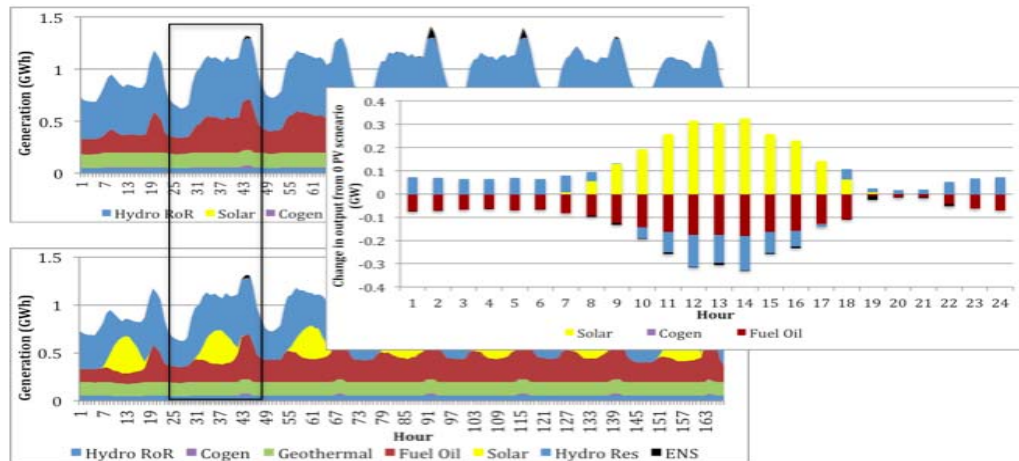
Note: Added solar capacity reduces daytime generation from fuel oil plants but cannot directly contribute to meet peak demand.

Source: Authors' calculations.

As Figure 4 shows, generation from fuel oil plants is displaced during the day by solar generation and during the evening by increased hydro-generation. 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 hydro-power plants is reduced to avoid additional start-up 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 4).

Figure 4: Changes in generation as a result of 500 MW solar penetration over a sample 24-hour period in the 2012 scenario



Note: Generation from diesel is displaced by solar generation during the day and by shifted hydro-power generation during the evenings and night.

Source: Authors' calculations.

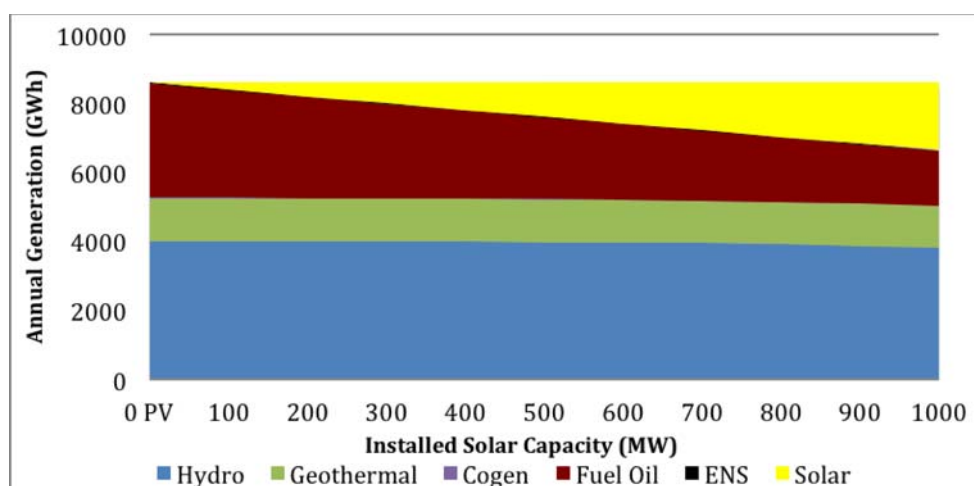
Notably, there remains unmet demand during peak hours on some days (represented as 'energy non-served') for a small number of hours, around 250 in the 0 PV scenario. This value is consistent with the 238 load-shedding events recorded during the same period by the Kenyan system operator (Kenya Power 2012d). 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 hydro-power 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 5 contains the comparison of total annual generation by technology for each scenario in the 2012 simulated year. At least up to 1000 MW, added solar simply substitutes for fuel oil production while hydro and geothermal production remain unchanged.

Total system costs

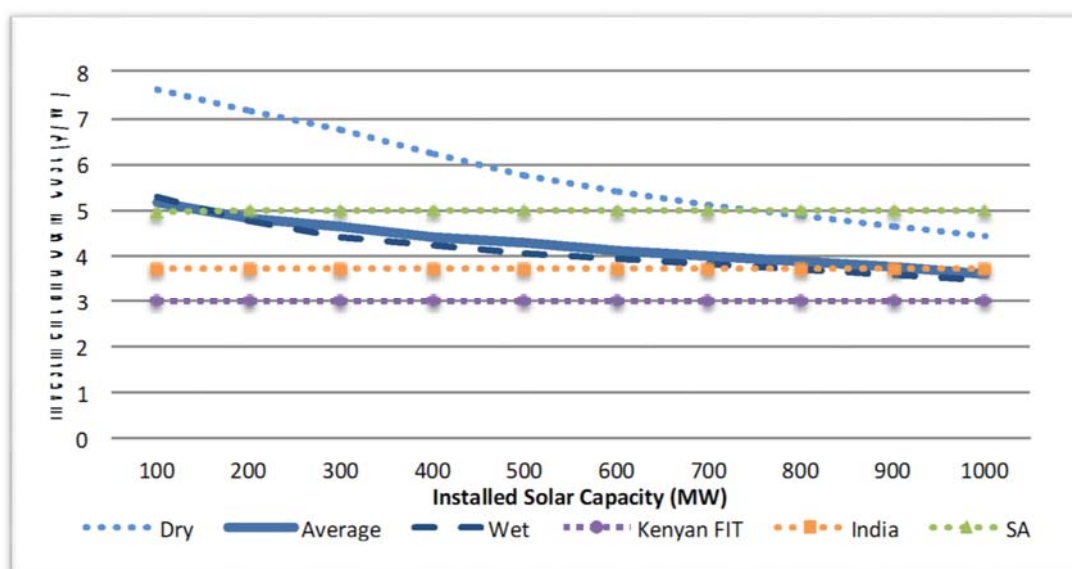
In 2012, reductions in system production costs for different levels of solar penetration are the result of reduced fuel consumption in fuel oil plants. These savings, expanded over the lifetime of the plant, can be readily converted to value per watt of solar capacity for different hydrological conditions. This value, shown in Figure 6, is equivalent to the amount the system operator would be justified in paying a solar plant owner for each watt of capacity he provides to the system. 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 hydro-power generation.

Figure 5: Annual generation output by technology under different solar scenarios in the 2012 system



Source: Authors' calculations.

Figure 6: 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



Source: Authors' calculations.

As Figure 6 shows, the maximum solar PV investments that are economically justified by the production cost savings fall from US\$5.1 to US\$3.6 per watt in an average year, as penetration levels increase from 0 to 1000 MW. In the dry year scenario, potential payment levels increase further to US\$4.4–US\$7.6 per watt 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 watt 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 remains 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, US\$0.10 per kWh and US\$0.15 per kWh, respectively

(Gowrishankar 2011; RoSA 2013), reveal that up to 800 MW of solar PV could be economically feasible at bid prices recorded in India, and the investment value at any tested penetration level is justified against the most recent bid prices experienced in South Africa.³ 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 US\$3 per watt (The World Bank 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.

3.2 Effect of solar PV in the 2017 power system

System operations

Under the 2017 National Plan scenario (Figure 7a), as solar is added to the system daytime production from fuel oil plants is reduced as compared to the 0 PV case.

Higher levels of solar penetration result in reductions from coal and imported sources. Since hydro-power 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.

In the 2017 Geo High scenario (Figure 7b), 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 per cent of solar generation is curtailed. This value increases to 75 per cent 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.

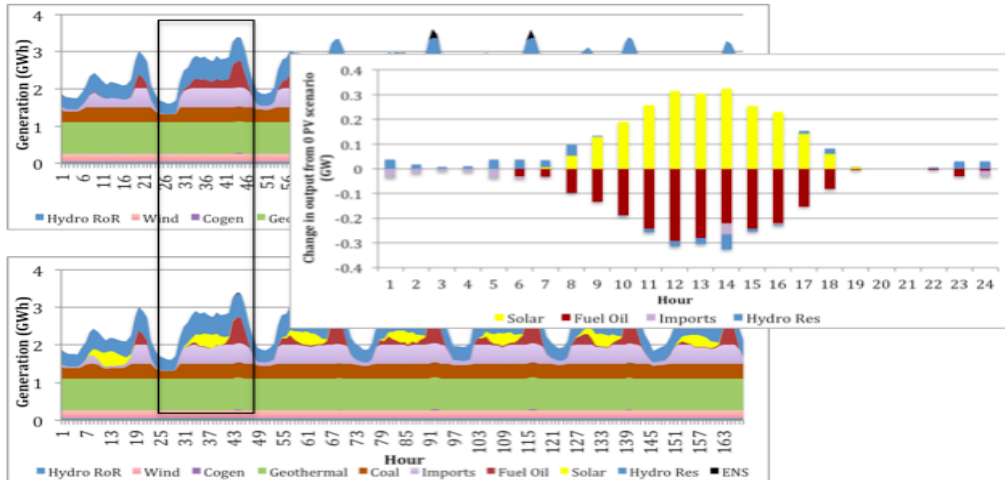
Finally, the 2017 Geo Low scenario (Figure 7c) reflects a more realistic generation mix as it avoids the need to reduce output from the geothermal plants seen in the 2017 Geo High scenario. This generation mix may also be a more accurate reflection of what investments may be completed by 2017. Historically, large-scale investments have faced significant delays and intermediate solutions in the form of increased diesel generation have been required to meet demand in the short term. 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 hydro-power 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 scenario as well as the 2017 National Plan, only with additional hydro storage capacity, or if the shape of the future demand curve were to

³ Ondraczek (2013) estimates the LCOE for PV in Kenya is US\$0.21 per kWh.

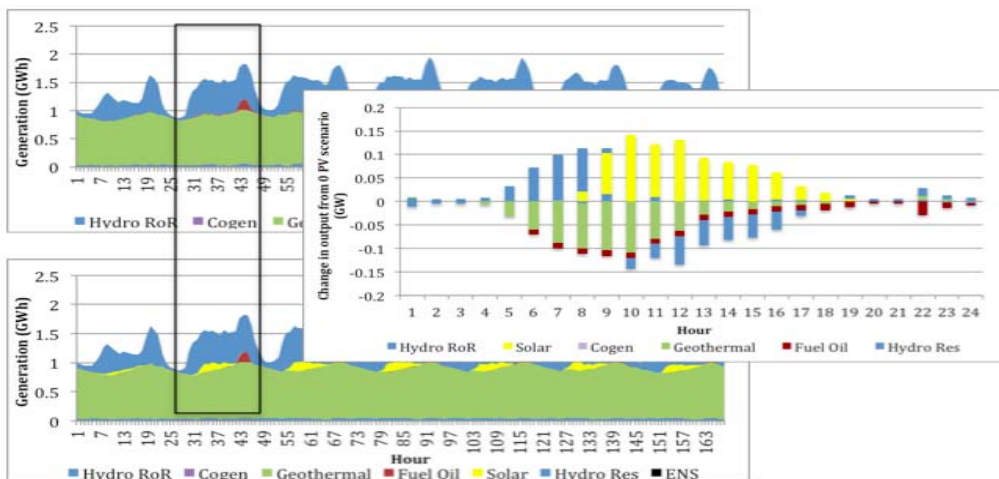
change such that peak demand corresponds with solar production, could added solar capacity potentially reduce the need for these plants.

Figure 7: Changes in generation output as a result of 500 MW solar penetration over a sample 24-hour period in the 2017 different scenarios

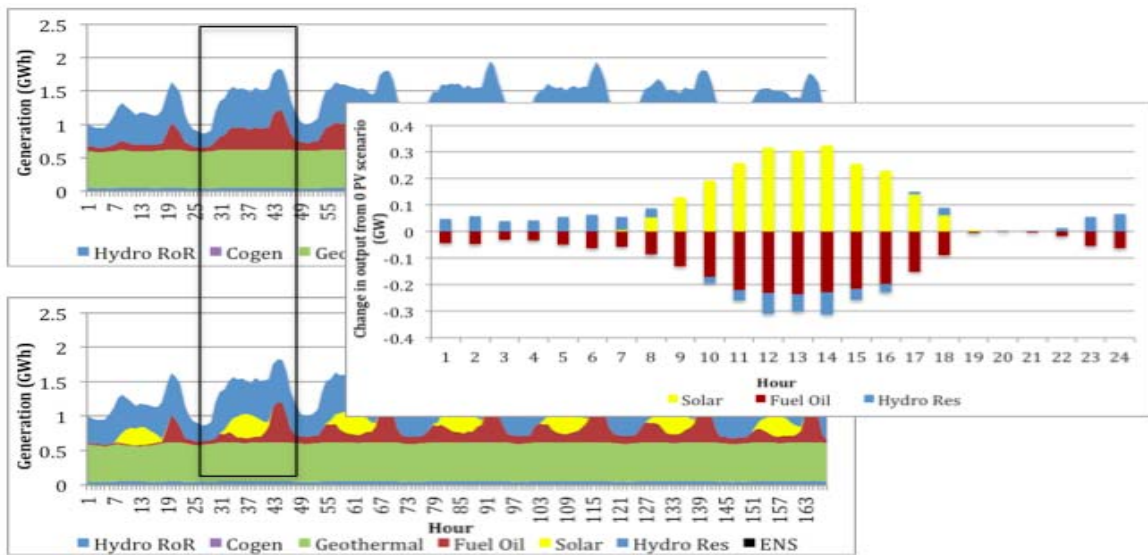
(a) National Plan



(b) Geo High



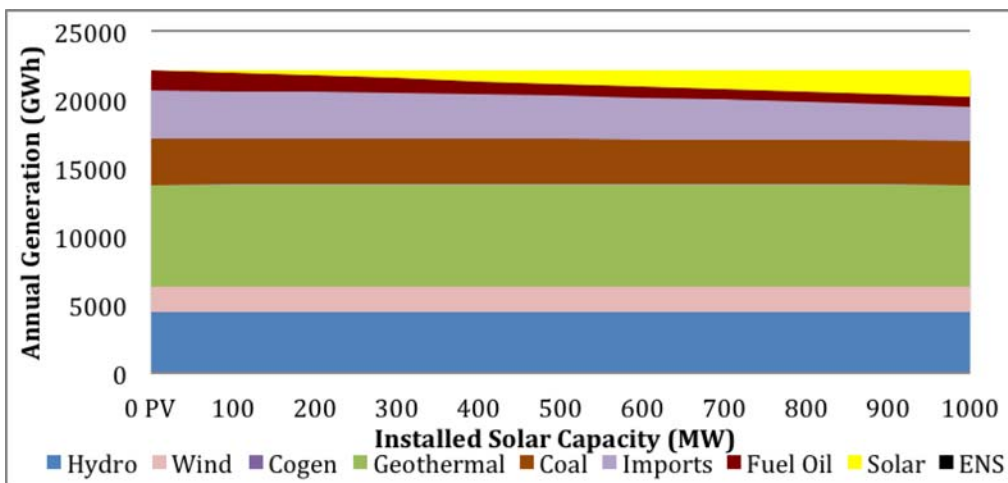
(c) Geo Low



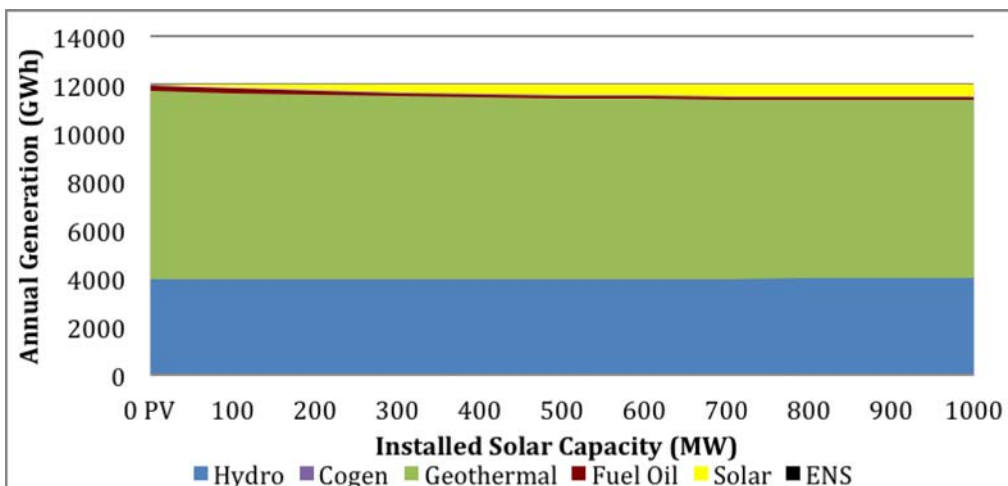
Source: Authors' calculations.

Figure 8: Annual generation output by technology for each solar PV scenario in the 2017 different scenarios

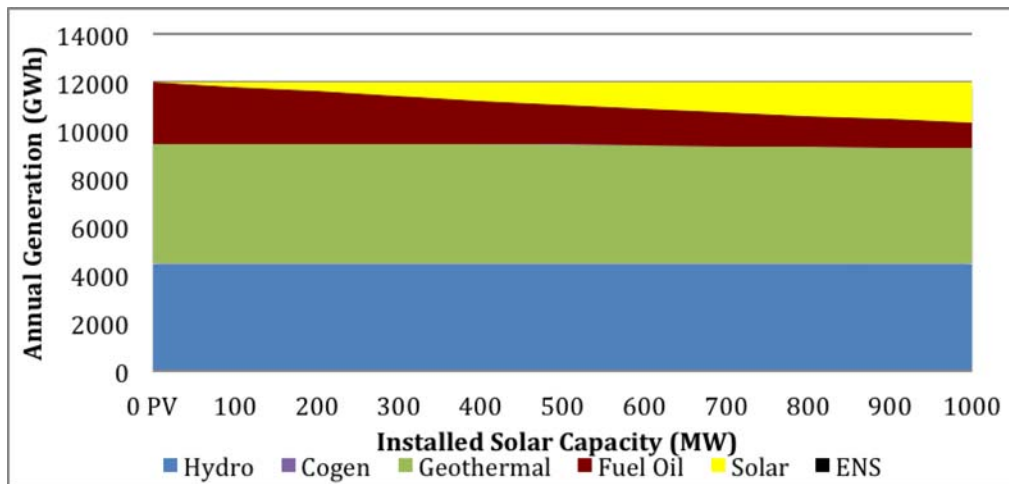
(a) National Plan



(b) Geo High



(c) Geo Low



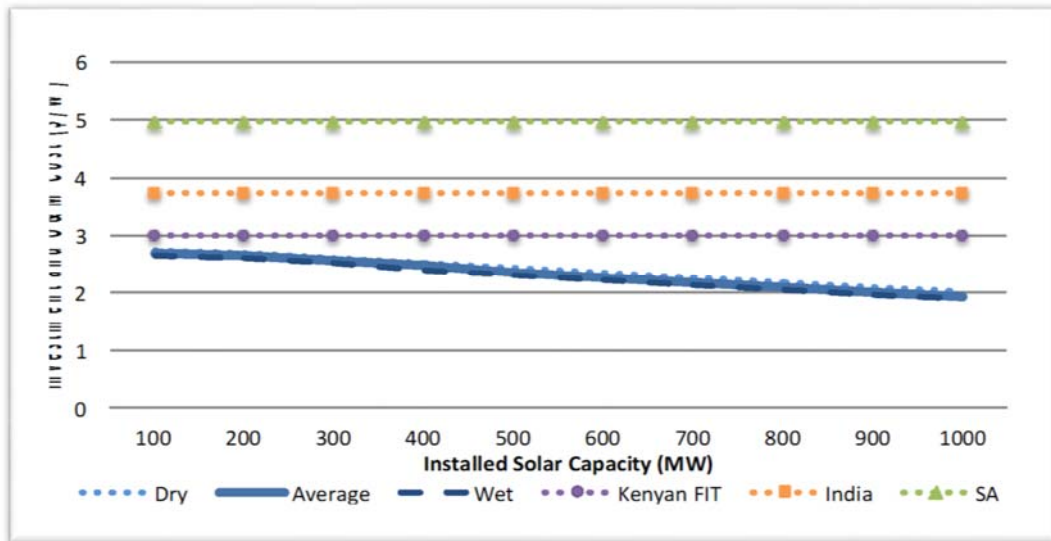
Note: In the National Plan and Geo High scenarios, there is limited generation from diesel plants to be curtailed resulting in displaced generation from less expensive sources such as geothermal, coal, imported and domestic hydro-power. In the Geo High scenario, large portions of solar generation must be curtailed due to the high levels of inflexible geothermal capacity.

Source: Authors' calculations.

Total system costs

For the 2017 National Plan (Figure 9), the production cost analysis of added solar PV in the 2017 system reveals a range of investment values of US\$1.9 to US\$2.7 per watt. For all scenarios, these values are significantly lower 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 bid rates in India. At plant costs achieved in South Africa, the value of solar on the system remains economical up to 500 MW.

Figure 9: 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 and India

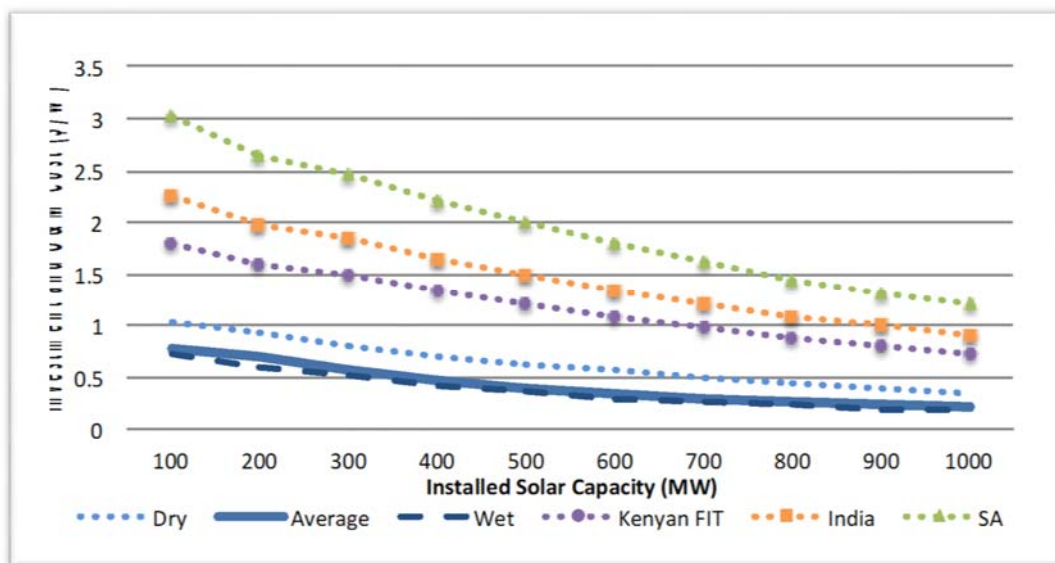


Note: In South Africa the value of solar PV investment remains economic up to 500 MW.

Source: Authors' calculations.

As with the National Plan scenario, the 2017 Geo High generation mix (Figure 10) 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 pre-existing hydro-power plants. The production cost analysis reveals a range of investment values of US\$0.2 to US\$1 per watt. These rates fall below the investment cost based on expected revenues from the Kenyan feed-in tariff and rates in India and South Africa. Unlike the 2012 and National Plan scenarios where limited or no curtailment of solar generation resulted in steady investment costs for each tested 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 10: 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



Source: Authors' calculations.

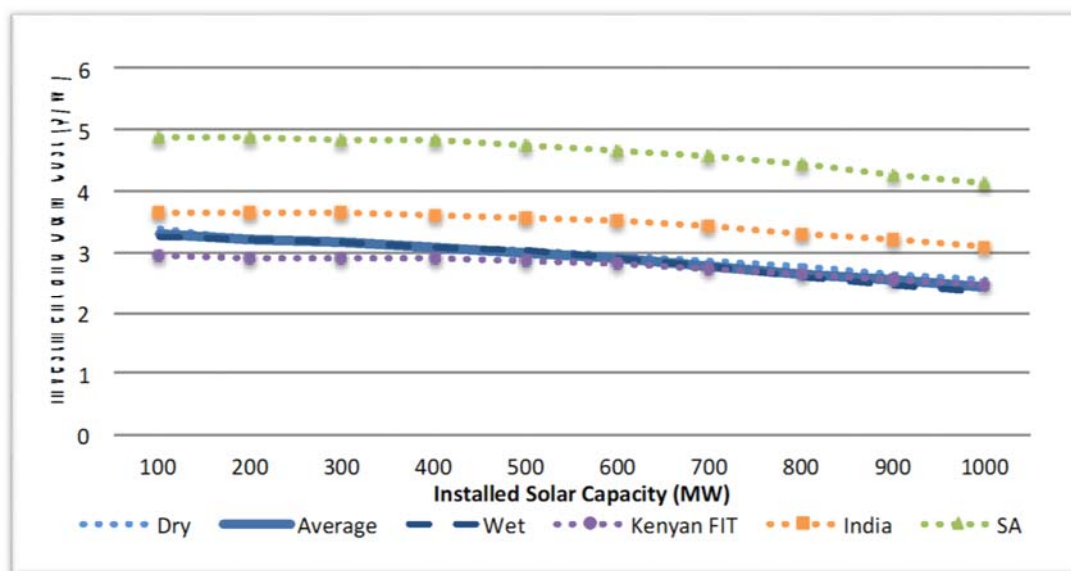
Finally, continued use of diesel generators in the **2017 Geo Low scenario** (Figure 11) provides an economic opportunity for solar PV to displace output from these plants. While added solar output displaces diesel generation almost exclusively in each solar scenario, the savings from reduced fuel consumption are lower than those seen in the 2012 simulated year because the most expensive kerosene-fuelled plants have been decommissioned by this time. The resulting range of investment values is US\$2.4 to US\$3.4 per watt. Based on these values, up to 700 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 and 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.

4 Discussion

Solar PV may offer an economical 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 solar PV to displace generation from fuel oil plants, currently providing 38 per cent of Kenya’s electricity. Under the existing Kenyan feed-in tariff and wholesale bids recently recorded in South Africa and India, the economically justified threshold for PV penetration in Kenya ranges from 800–1000 MW.

Figure 11: 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



Source: Authors’ calculations.

Proposed 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. 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 100–700 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 plan was not included in this analysis. If solar PV could be sited near major load centres, 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 projected demand profile for 2017 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 favour the economics of solar PV over diesel. Uncertainty in demand growth would also favour solar PV over other large-scale projects that require long lead times and supporting infrastructure.

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 which 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. There are significant opportunities to displace fuel oil generation with solar PV. Across all developing country regions, 20 per cent of electricity production is derived from oil-based plants (IEA 2012a). Currently, all but five countries in Africa derive some portion of grid-connected capacity from these plants and over 28 countries have over 50 per cent total capacity from oil plants (IEA 2012a). On the other hand, the characteristics that may make solar PV a favourable option in Kenya—an abundant solar resource and large capacities of untapped reservoir hydro-power—are also present across the continent.

5 Conclusion and policy implications

That fuel oil use could be substantially and economically replaced by solar PV in Kenya and, potentially, in many other Sub-Saharan African countries is promising for those concerned about climate change, energy independence, and the cost of electricity generation. However, under current planning methodologies where technologies are evaluated on an individual project level using a static LCOE of each technology, solar PV capital investment costs remain too high to compete with those of coal, geothermal, hydro, and wind power. The system-level approach used in this study shows that the economic value of a candidate technology is not a static metric but depends on the demand and generation assets of the particular system.

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 centres. 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. These results can be extended to other countries where there exist a higher-cost competitor to be displaced and low-cost storage, most likely in the form of reservoir hydro capacity.

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 providing insights as to what geographic and capacity constraints the existing network may impose on potential project sites. Additionally, supplementary 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 co-ordinated fashion or favour concentrated solar power technologies.

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 solar and wind may be a viable option for many Sub-Saharan African countries. Solar PV may also be attractive in non-hydro-based systems where diesel is the primary source of base load power. For evaluation of the penetration limits of solar PV in any of these systems, a similar analysis may be used that takes into account the particular system configuration.

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