Impact of novel and disruptive approaches/technologies on a distribution utility: A Kenyan case study

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The electrical power sector in Africa is rapidly evolving as countries adopt novel and disruptive approaches/technologies to fulfil electrification goals and stimulate private investment in order to ensure supply adequacy and grow their economies. This all while remaining cognisant of the requirement for a sustainable sector via combinations of energy efficiency (EE), solar water heater (SWH) deployments, frameworks for net metering and Feed-in Tariffs (FITs) for embedded generation, utility scale renewables projects and Demand Side Participation (DSP). The consequences of these novel and disruptive approaches/technologies does mean that the unidirectional power-flow through distribution utilities and municipalities (from bulk suppliers to off-takers) is changing. As a result, reduced energy sales are expected while still having to cover fixed costs including components of bulk purchase costs from existing suppliers, overheads as well as network investment and maintenance costs. This paper focusses on the impact of the abovementioned novel and disruptive approaches/technologies via a case study on the main distribution utility in Kenya, Kenya Power and Lighting Company (KPLC).

1. Introduction

The well-known electric utility 'death spiral' (as shown in Fig. 1) was initially hypothesized in the 1980s following increased utility costs from large infrastructure investments but in recent times has been re-introduced as a result of novel and disruptive approaches/technologies. These include inter alia energy efficiency (EE), solar water heater (SWH) deployments, embedded generation (EG), utility scale renewables projects, Demand Side Participation (DSP) and distributed standby generation. As a result, electric utilities have to consider an evolving business landscape where electricity service provision is not merely the legacy business model of wholesale power purchases from bulk providers sold onto end-users at a pre-determined mark-up. Electric utilities have to realise that involvement via active advocacy of regulatory policy changes that promote end-user benefits and direct involvement in programs (where regulatory policy allows) is fundamentally part of their mandate as utility service providers.

The electrical power sector in Africa is quite unique in that it comes from a small, rapidly growing and evolving base as countries pursue significant electrification while stimulating private investment to ensure supply adequacy and resultant economic growth. The large majority of African nations have vertically integrated utilities where all services are performed by one company (generation, transmission, distribution and customer services). When vertically integrated, the changing business landscape previously mentioned is not as relevant as a result of cross-subsidisation and cost-sharing between business units. This paper is more applicable for countries where some level of unbundling in the distribution sector has occurred e.g. Regional Electricity Distributors (REDs), Distribution Company (DisCo), local municipalities. It focusses on the impact of the abovementioned novel and disruptive approaches/technologies via a case study on the main DisCo in Kenya, Kenya Power and Lighting Company (KPLC).

The paper is structured to include a brief overview of the Kenyan power sector followed by an outline of the approach taken in assessing the effect of novel and disruptive approaches/technologies on KPLC. The analytical model that is used is then described followed by results, analysis and a concluding section.

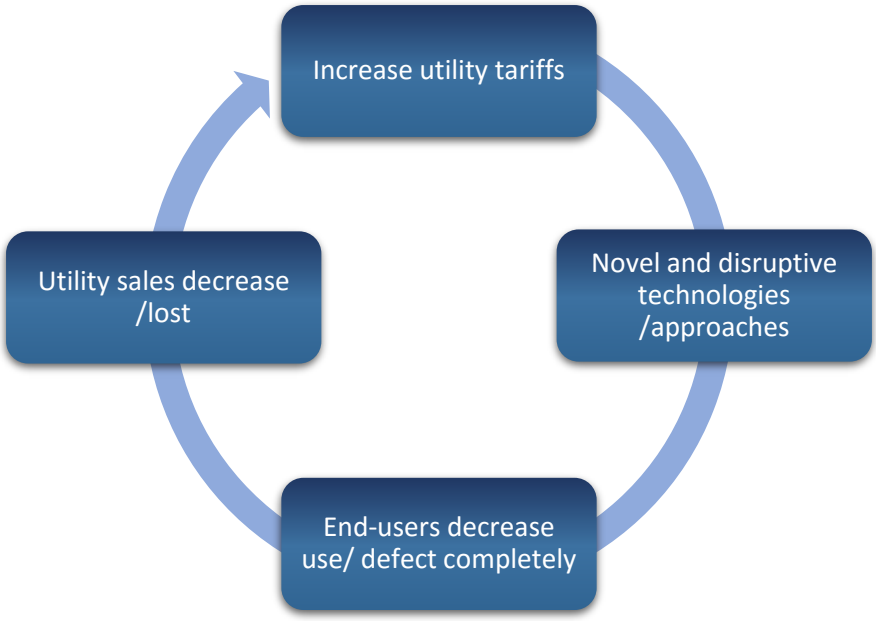

Fig. 1: The hypothesised electric utility death spiral

2. Overview of the Kenyan power sector

In 2014, Kenya experienced a peak demand of 1 468 MW (in November) with an annual energy demand of 7 298 GWh and losses of 1 596 GWh [3]. A typical daily demand profile for Kenya is shown in Fig. 2 for one week [4]. The profile shows a demand profile with a morning peak between 09h00-10h00 while the evening peak typically occurs at 20h00. The generation capacity in the Kenyan power system (for 2014) is summarized in Tab. 1. As can be seen, the 1 968 MW installed capacity was made up of hydro capacity (47%) followed by thermal capacity (33%), geothermal (18.5%) and renewables (1.5%).

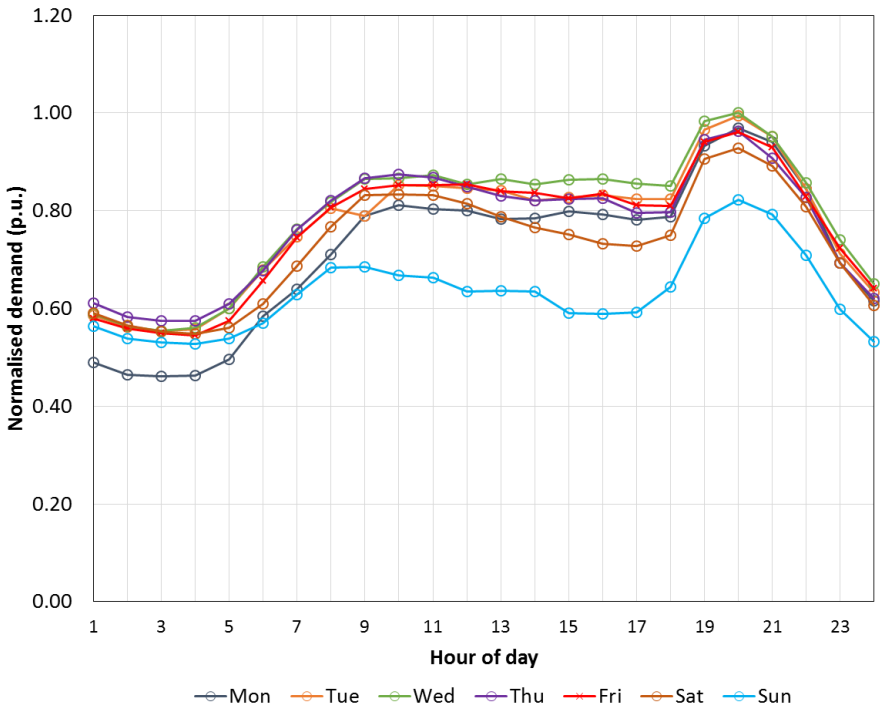

Fig. 2: Normalised Kenya daily demand profile (Monday-Sunday)

Tab. 1: Summary of Kenya generation capacity (2014)

	Installed capacity	***Rated capacity***
	MW	***MW***
Geothermal	363.4	347.8
Hydro	923.9	797.5
Renewables	30.3	20.6
Thermal	650.2	615.2
Total	1 967.8	1 781.2

3. Approach

The approach taken in this paper is analytical in nature. The study uses the energy market modelling tool, PLEXOS® Integrated Energy Model [5]. The PLEXOS® functionality used for this study includes the optimisation of maintenance scheduling and inclusion of random forced outage events along with the ability to decompose medium-term constraints for use in short-term production cost modelling (unit commitment and energy dispatch). During these phases, PLEXOS® formulates mathematical objective functions for optimisation by Linear Programming (LP) and Mixed-Integer Programming (MIP) approaches solved by commercial solvers integrated into the PLEXOS® Engine (CPLEX, Xpress-MP, GUROBI or MOSEK). The optimisation is performed in a Windows environment on a 64-bit architecture with two Intel®~Xeon® E5-2670 processors operating at 2.6 GHz (8 cores each) and 100 GB RAM.

A fundamental dataset of the Kenyan power system has been developed and benchmarked to include supply side resources, equivalent networks and the demand side. From this, the dataset is benchmarked to public domain information (where available) and generally accepted industry practice (where information is not available) using the 2014 calendar year as a base. This model is then supplemented with various novel and disruptive approaches/technologies to assess the effect of these on KPLC in terms of unit commitment and energy dispatch of the overall system, energy volumes, system losses, wholesale energy prices, fuel costs and system reliability.

4. Model development and input assumptions

4.1. Supply resources

In Kenya, power supply consists of KenGen as the dominant generation provider complemented by a number of IPPs. The generation capacity, as presented in *Tab. 1*, consists of a mix of hydro, geothermal and thermal (HFO, LFO and kerosene fired) generation capacity with a small renewable portfolio (wind and biomass). While information such as maximum capacity, rated capacity, fuel costs and annual energy constraints (hydro, wind) are explicitly reported in [6], other technical and economic parameters have been either assumed from general industry practice or derived from reported values, with assumed fixed and variable costs of generators benchmarked against data from [3], [17]. Annual energy constraints for the significant hydro in Kenya were assumed to follow a seasonal pattern as presented in *Fig. 3*.

Imports from and exports to neighbouring countries (Uganda, Ethiopia and Tanzania) are modelled with upper limits derived from the 2014 figures from [6] and capacity limits imposed by the thermal/stability limits of existing interconnectors between the countries.

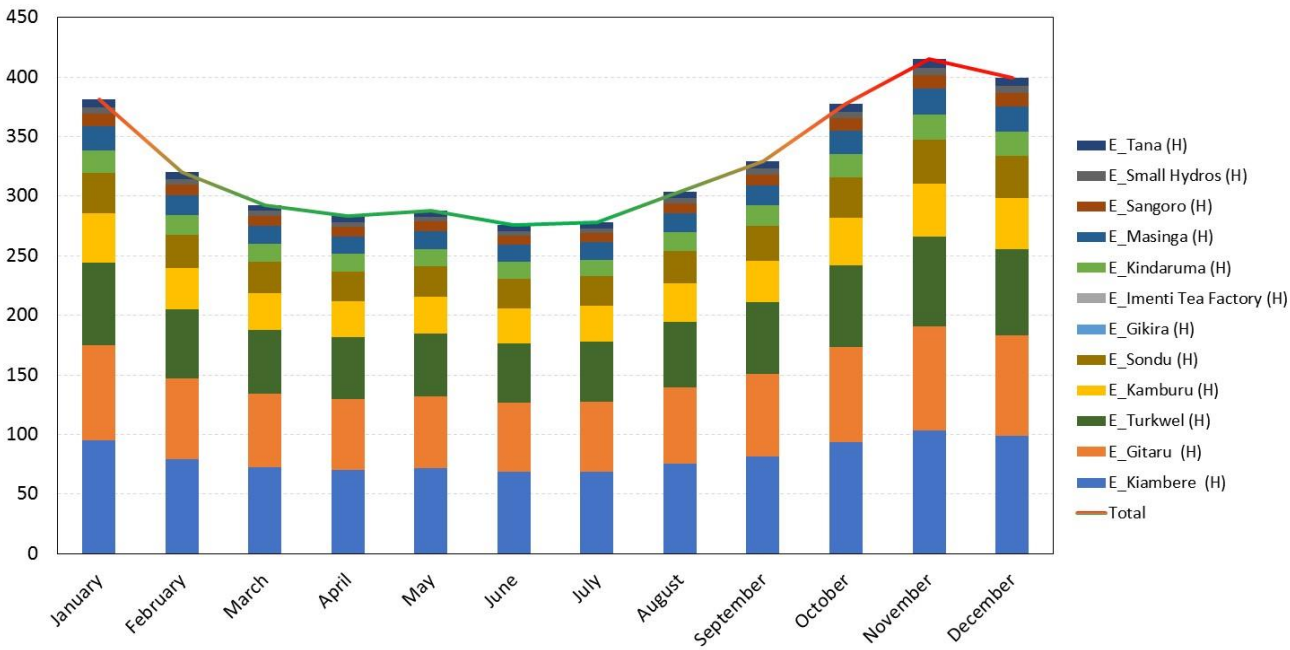

Fig. 3: Assumed hydro energy generation monthly profile (2014)

4.2. Demand, network and losses model

The Kenyan transmission network is modelled as four different regions (West, Coast (East), Nairobi and Mt. Kenya), all interconnected through the central Nairobi region, in order to model the geographical dispersion of generation sources and demand. Transmission (regional interconnectors) and distribution (internal network between generation and load) network are both modelled with linear loss functions. These are parametrised iteratively such that an approximate 1:3 ratio of transmission to distribution losses is maintained and that total losses matched those reported in [6]. The share of distribution losses per region is according to the proportion of electricity sales in each region while a single linear loss function was assumed for all transmission lines.

The seasonal variation of annual demand is assumed to be sinusoidal around a November peak, as shown in *Fig. 4*. The actual peak demand values per region are reported (as shown in *Tab. 2*) with a single demand profile assumed for Kenya as a whole (as presented in *Fig. 2*) and proportion of electricity sales per region used for the split of demand amongst the four regions.

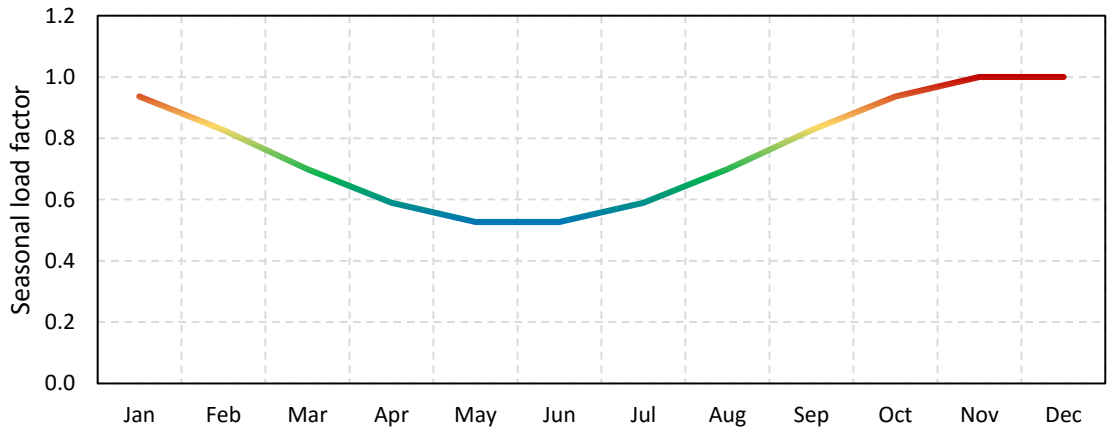

Fig. 4: Seasonal variation in the demand profile around a November peak

Tab. 2: Summary of the regional demand-model

Property	***Units***	***Coast***	***Mt. Kenya***	***Nairobi***	***West***
Peak demand	***MW***	267	159	768	298
	%	17.9	10.7	51.5	20.0
Energy sales	***GWh***	1256	598	3776	1121
	%	18.6	8.9	55.9	16.6

4.3. Novel and disruptive approaches/technologies

All of the novel and disruptive approaches/technologies modelled have been included with representative "high", "medium" and "low" penetration/adoption levels to consider what effect they would have on the power system and particularly on KPLC. However, for brevity, only the "high" penetration/adoption level is reported in this paper. The load was assumed to be comprised of residential, commercial and industrial components, with the different class of sales reported in [6], which are used to imply the effects of certain disruptive technologies which are load-dependent.

4.3.1. Energy Efficiency (EE)

Although the authors understand that there are a range of EE initiatives available, each with their own cost structures, these have not been explicitly modelled as it is not the focus of the study. The focus is to assess the effect of selected EE initiatives (space heating/cooling and lighting) on the power system, and specifically on a distribution utility like KPLC.

For space heating/cooling component of EE, demand reduction in each hour of the year is calculated based on a quadratic function of temperature in each of the four regions (as outlined in section 4.2) for residential, commercial and industrial loads. This quadratic function assumes that there is a reduction in conventional heating or cooling loads that would occur when the temperature is above/below a certain threshold temperature, with 2014 temperature data for four locations in Kenya being used. These upper and lower thresholds were therefore assumed to be 23°C and 15°C respectively. An example of the reduction in power demand as a function of temperature is given for two locations (Nairobi and Coast) in Fig. 5.

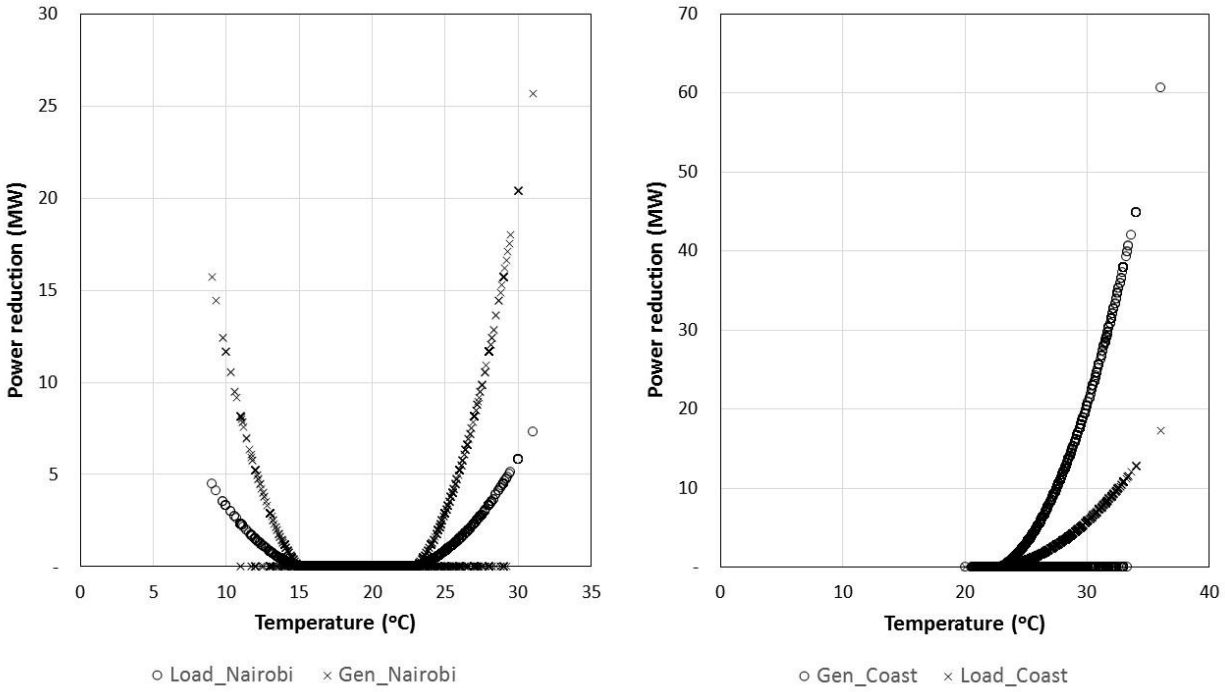

Fig. 5: Example of modelled space heating/cooling power reduction vs temperature model for two locations (2014)

For the lighting component of EE, the impact of particular lighting EE deployments is explored. Weekly lighting profiles for commercial, industrial and residential sectors were assumed as per *Fig. 6*. In deployment of EE measures, it was assumed that lighting loads would be reduced by 80% with lighting representing a certain percentage of the annual energy in each sector. This was assumed as 20%, 15% and 15% for residential, commercial and industrial sectors respectively.

4.3.2. Solar Water Heating (SWH)

The deployment of SWHs would see a significant reduction in residential load as a substantial component traditionally present for electrical geysers is removed from the demand profile. A typical load profile for an electrical geyser during peak and off-peak (i.e. cold and hot) periods is assumed from [20] (as shown in *Fig. 7*). Historical country temperature data [21] is then used to populate the intermediate geyser load profiles.

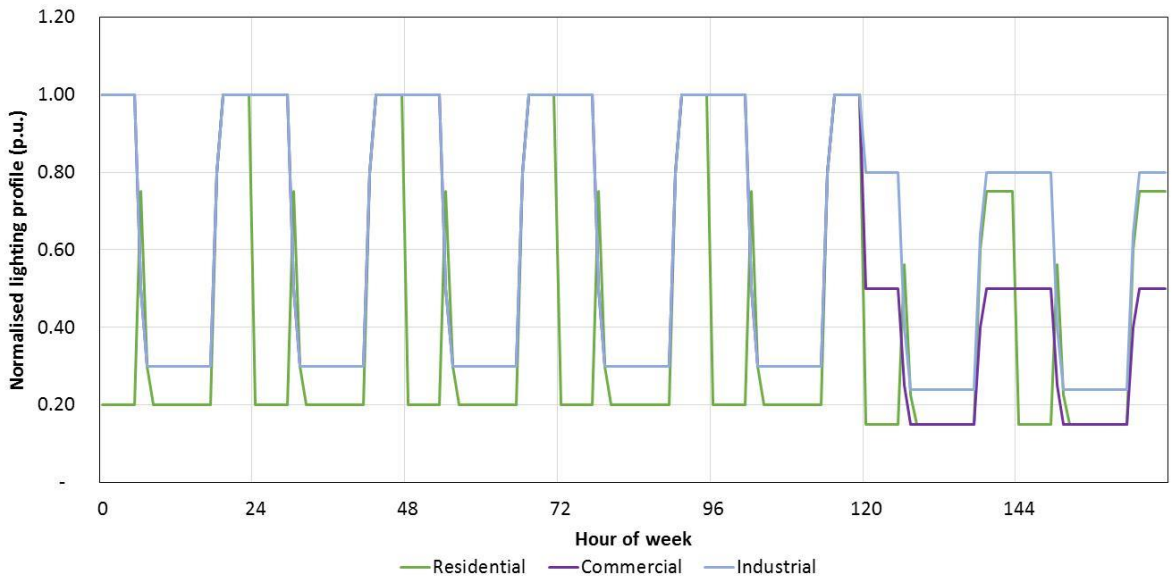

Fig. 6: Normalised lighting profiles for each demand component (assumed)

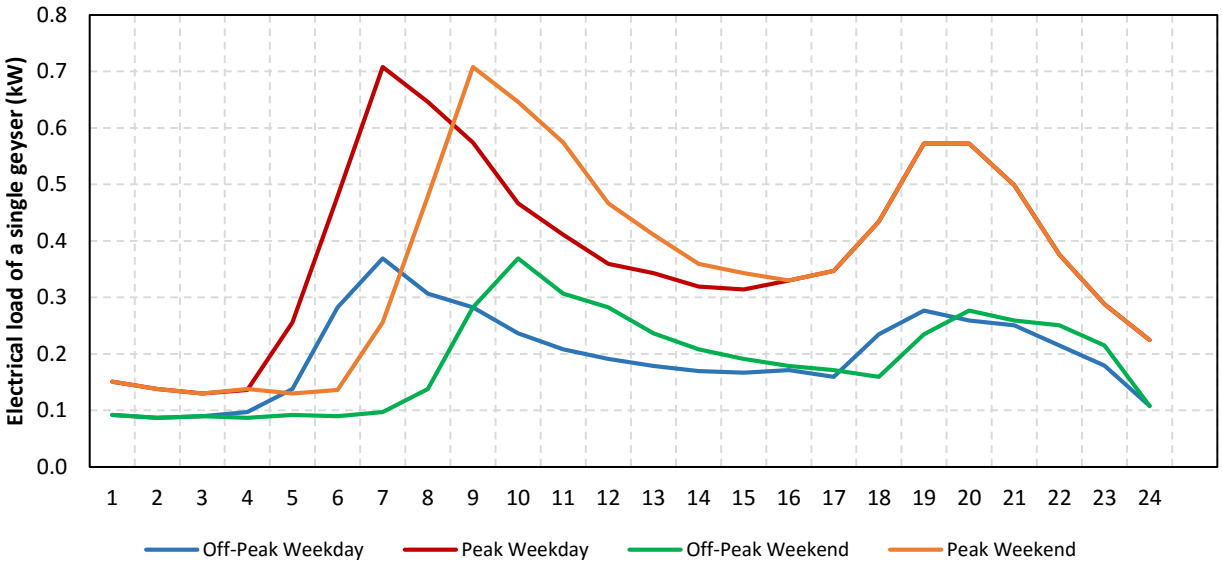

Fig. 7: Example of the electrical load profile of a geyser for a single household

4.3.3. Embedded Generation (EG)

Embedded Generation (EG) is explored in three different manners, namely residential rooftop solar PV, commercial rooftop solar PV and cogeneration in the industrial sector. The balance between local load and the EG at different times of the day results in a reduction in the load requirement from the grid (load offset) as the EG services local load and can be accompanied by surplus supply that is exported to grid when the EG exceeds local load (net generation). The load profiles for the different sectors are presented in *Fig. 8* [22].

Hourly Global Horizontal Irradiance (GHI) data for a full-year period at four different Southern African locations [23] were used for solar irradiation and resultant power output from the embedded solar generation. For the purpose of this study, the installed capacity of rooftop solar PV was assumed to be such that it matches the peak demand where it is installed. An example of the profiles for load, solar PV output, load offset and net generation for residential rooftop solar PV installations is presented in *Fig. 9*.

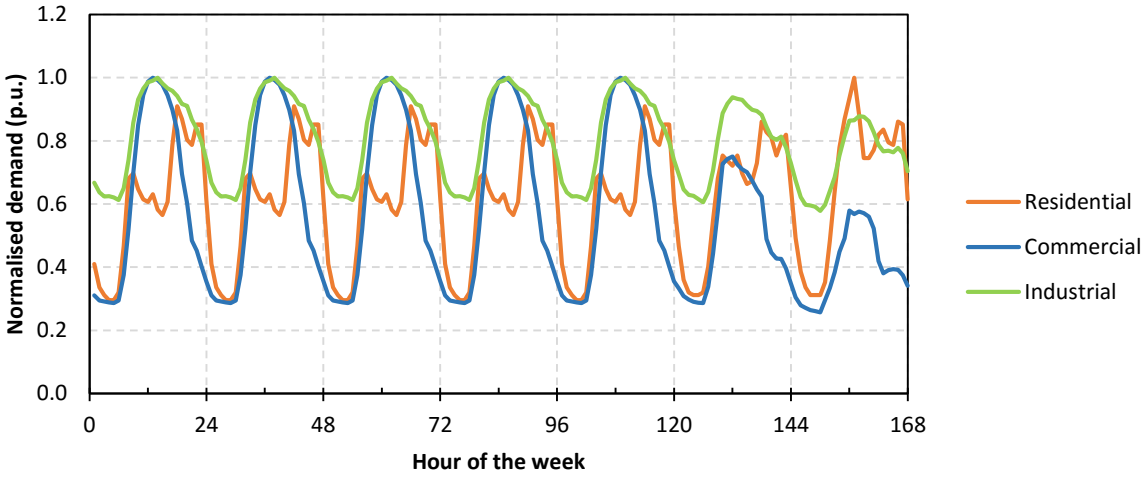

Fig. 8: Weekly demand profiles for residential, commercial and industrial type loads

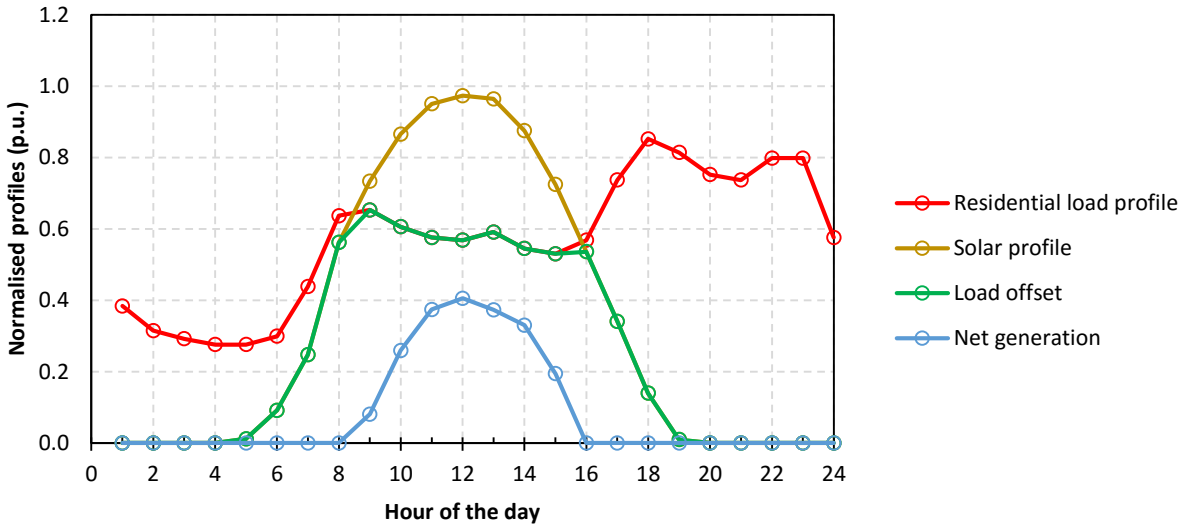

Fig. 9 Example load offset and net generation profiles for residential rooftop solar PV

For cogeneration plants, a similar model was followed whereby a portion of the industrial local load (thermal and electrical) is serviced by cogeneration (i.e. load offset) while another portion is then exported to the grid (i.e. net generation). As the output from the cogeneration plant is linked to the load of the industrial process, the industrial load profile presented in *Fig. 8* is used as a profile for both the load offset due to the cogeneration and the subsequent power exported to the grid, with a fixed proportion these two values assumed from a known plant in East Africa [24].

The size of the EG was chosen such that the load offset for each sector (i.e. residential, commercial or industrial) in each region was ≈60% of the estimated peak load, as summarised in *Tab. 3*. With respect to both rooftop solar PV and industrial cogeneration, the tariffs for these resources are calculated using the latest published Kenyan Feed-in Tariff (FiT) Policy from the Ministry of Energy and Petroleum in Kenya [25]. Cogeneration plants are assumed to have an availability of ~82%, due to outages that are spread through the year.

Tab. 3: Summary of the EG model

Technology	***Sector***	***Max capacity***				***Feed-in tariff***
		Coast	***Mt. Kenya***	***Nairobi***	***West***	
		MW				***USD/MWh***
Solar PV	Commercial	60	63	216	123	120
Solar PV	Residential	45	33	168	54	120
Cogeneration	Industrial	30	12	75	21	110

4.3.4. Utility-scale renewables

Large, utility-scale renewable programs are modelled in the form of solar PV and wind in the West and Mt. Kenya regions respectively. Both are modelled as 400 MW plants, roughly 20 % of the 2014 installed capacity in Kenya. Hourly solar [23] and wind [26] data from sites in South Africa were used, with a capacity factor of 21.2% and 40% for solar and wind respectively.

4.3.5. Demand Side Participation (DSP)

The maximum amount of Demand Side Participation (DSP) modelled is ≈20% of maximum demand in 2014 (290 MW) and shared amongst the different regions that are modelled based on their share of energy sales. The price paid to DSP providers (USD 400/MWh) is homogenous across all regions and based on a simple mark-up on the energy price of the last generator in the supply stack for 2014 (Aggreko diesel engines). It is also constrained to a maximum activation time of 3 hours, with only one activation allowed per day and 52 activations over the entire year. A summary of DSP modelled is shown in *Tab. 4*.

Tab. 4: DSP model parameters (max)

	Max capacity	***Providers***	***Total Capacity***	***Activation time***	***Max activations***		***Total energy***	***Price***
	MW	***#***	***MW***	***Hrs***	***/day***	***/year***	***GWh***	***USD/MWh***
Nairobi	0.5	304	152.0	3	1	52	23.71	400
Coast	0.5	111	55.5	3	1	52	8.66	400
West	0.5	111	55.5	3	1	52	8.66	400
Mt.Kenya	0.5	55	27.5	3	1	52	4.29	400
Total		581	290.5				45.32	

5. Results and analysis

5.1. Base case

A base case was run without any disruptive technologies/approaches included to benchmark the model. System peak (excluding losses) occurred in November (1 468 MW) with system minimum in May-June (357 MW). The annual energy balance is shown in *Fig. 10*. Unserved energy (USE) is used as a proxy for system reliability and is 3.95 GWh. The system dispatch for the base case is shown in *Fig. 11* for a week in the peak month of November. As can be seen, hydro and geothermal generation supply base load to mid-merit power, thermal generation acts as a mid-merit and peaking resources along with purchases (imports) while renewables are a self-dispatched resource. There is also a small amount of energy imports (purchases) during peak periods when the system is constrained along with USE when imports are not available.

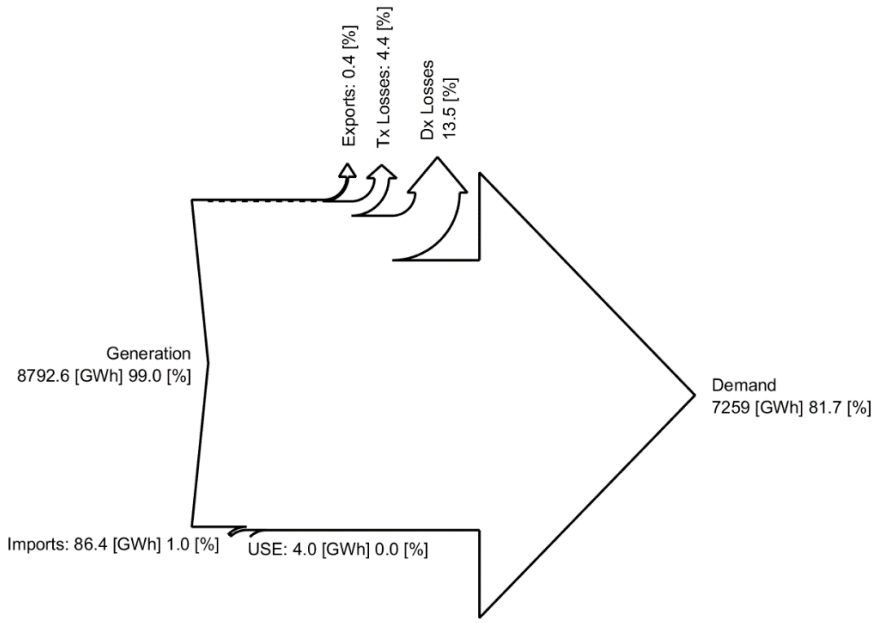

Fig. 10 Annual energy balance (base case)

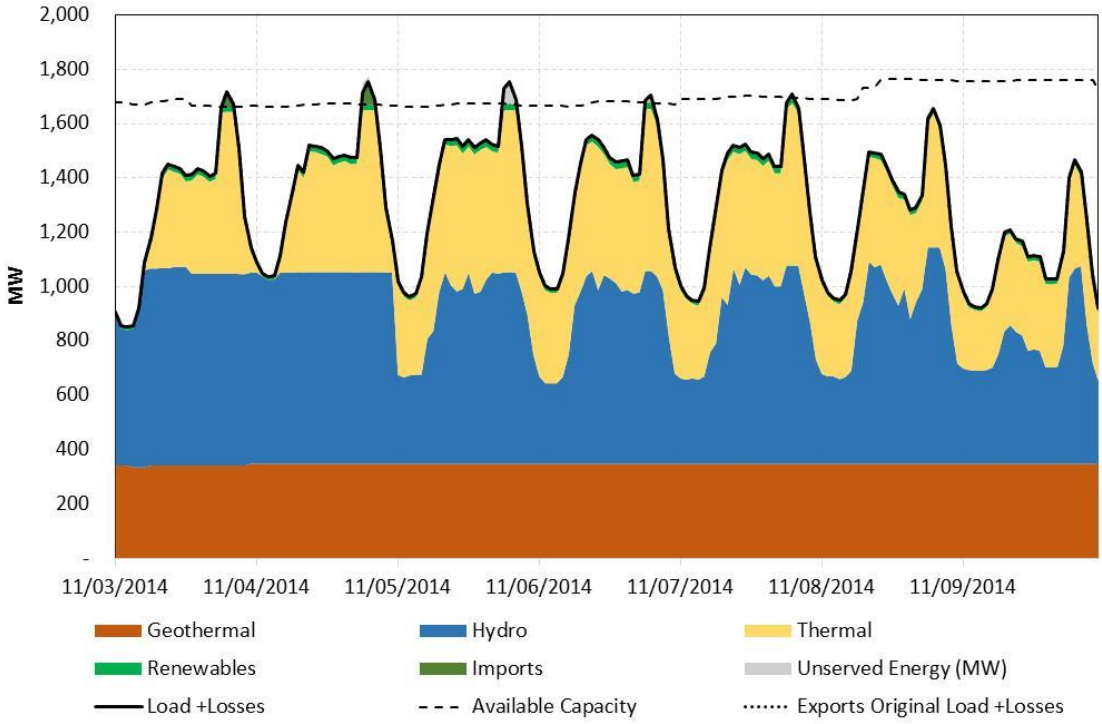

Fig. 11 Dispatch for one representative week (base case)

5.2. The effect of disruptive technologies

5.2.1. *Annual energy and peak demand*

The aforementioned disruptive technologies have a significant effect on system characteristics (peak/min demand, unserved energy, energy sales) as shown in *Tab. 5*. These changes then have a subsequent impact on the system energy price, also shown in *Tab. 5*. Furthermore, the system energy price is presented in terms of its different cost components, including the Cost of Unserved Energy (CoUE), in *Fig. 12*.

Tab. 5: The change in key system characteristics from the base case due to disruptive technologies

System characteristic	***EE***	***SWH***	***EG (Solar)***		***Industrial cogeneration***	***Utility-scale solar PV***	***Utility-scale wind***	***DSP***
			Res.	***Comm.***				
				% change relative to the base case values				
Peak demand	-15.2	-14.0	0.0	0.0	-0.6	0.0	0.0	0.0
Min demand	-53.3	-53.3	-6.1	-10.9	-41.0	0.0	0.0	0.0
Energy sales	-17.3	-17.4	-5.9	-10.1	-27.6	0.0	0.0	0.0
USE	-17.5	-100.0	-89.5	-89.7	-100.0	0.0	13.4	-79.1
Losses	-5.0	-8.9	-2.9	-3.5	-21.1	16.4	7.6	0.0
System energy price	-0.8	-3.7	1.0	4.7	-0.4	0.6	-0.8	-1.9

From these results, there is a visible trend that all of these technologies are having a significant impact on the operation of the system, thereby affecting the different cost components of the system energy price. Firstly, for all disruptive technologies with the exception of utility-scale renewables and DSP, there is a reduction in energy sales. As a result, the fixed cost components for generation and T&D infrastructure leads to an increase in this component of the energy price.

Despite this, in most cases this increase in the fixed cost component is offset by a significant reduction in the fuel cost component. This is both due to less annual energy demand but also due to the peak demand of the system being reduced leading to less of the relatively expensive thermal generation being required. This is demonstrated for the space heating/cooling measures in *Fig. 13*, however a similar trend was observed for both SWH and industrial cogeneration. The only difference with industrial cogeneration is that due to simultaneous outages of these plants, the reduction in the peak demand observed over the entire year is very small. Meanwhile, both residential and commercial solar EG lead to

a notable reduction in annual energy demand, however it had no impact on the peak demand due to its peak output occurring around midday.

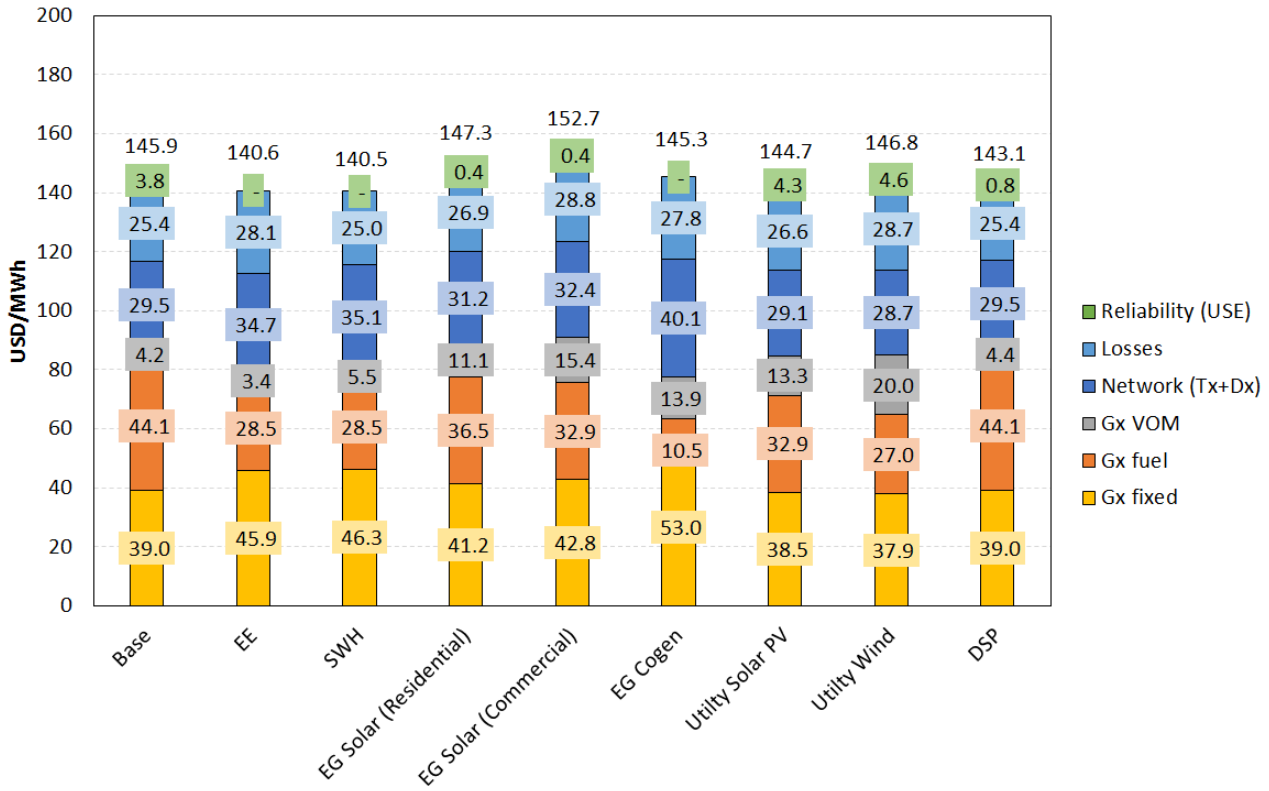

Fig. 12 Effect of disruptive technologies/approaches on equivalent system energy price (2014)

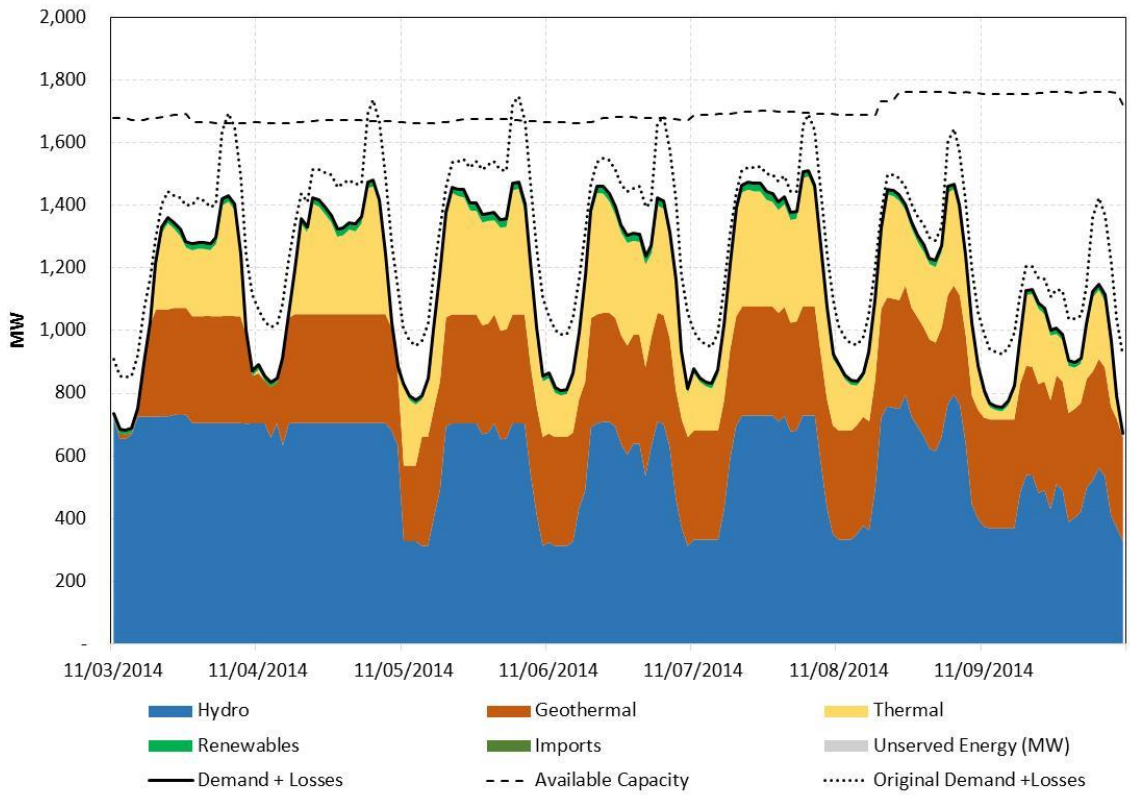

Fig. 13 Dispatch for one representative week (EE rollout)

5.2.2. Losses on transmission and distribution networks

Another positive effect of the EE measures is that losses on the system were reduced in all cases. This is due to less annual energy demand and, in the case of EG, the direct servicing of load and lack of distribution losses. Despite this, the price component of losses to the system energy still increased in the majority of these cases, which is most likely due to the re-dispatch of cheaper generation further from the load centres. Meanwhile, an opposite effect can be seen to occur with the utility-scale renewable plants, with a significant increase in system losses which can be attributed to the remote location of these renewable projects, with only a small load to service in the Mt. Kenya and West regions for wind and solar respectively.

5.2.3. Unserved energy

All disruptive technologies, except for the utility-scale renewable projects, helped to reduce USE to varying degrees, mostly due the overall reduction in the system energy requirement, increasing the reliability of the system. USE is completely eliminated with industrial cogeneration, EE measures and SWHs due to the large reduction in annual energy and the significant shaving of peak demand. Solar EG has no direct impact on peak demand or peaking capacity, it still leads to a significant reduction of USE due to constrained hydro capacity that can be re-dispatched to avoid USE.

The DSP program is predominantly used at peak times (as expected) and resulted in a significant decrease in USE. However, DSP resources were under-utilised as only 3.91 GWh out of a possible 45.32 GWh was used throughout the year. This is mostly as a result of the concentrated period when the system is constrained (November-December), the limited amount of time a DSP resource can be used (3 hours) and the number of times it can be used daily (once). An example of this is shown in *Fig. 14* where USE occurs for certain hours from Wednesday-Friday as a result of limited capability of the DSP resources available. The DSP program attempts to minimize this by activating for as long as possible but is not able to fulfil the complete demand requirement.

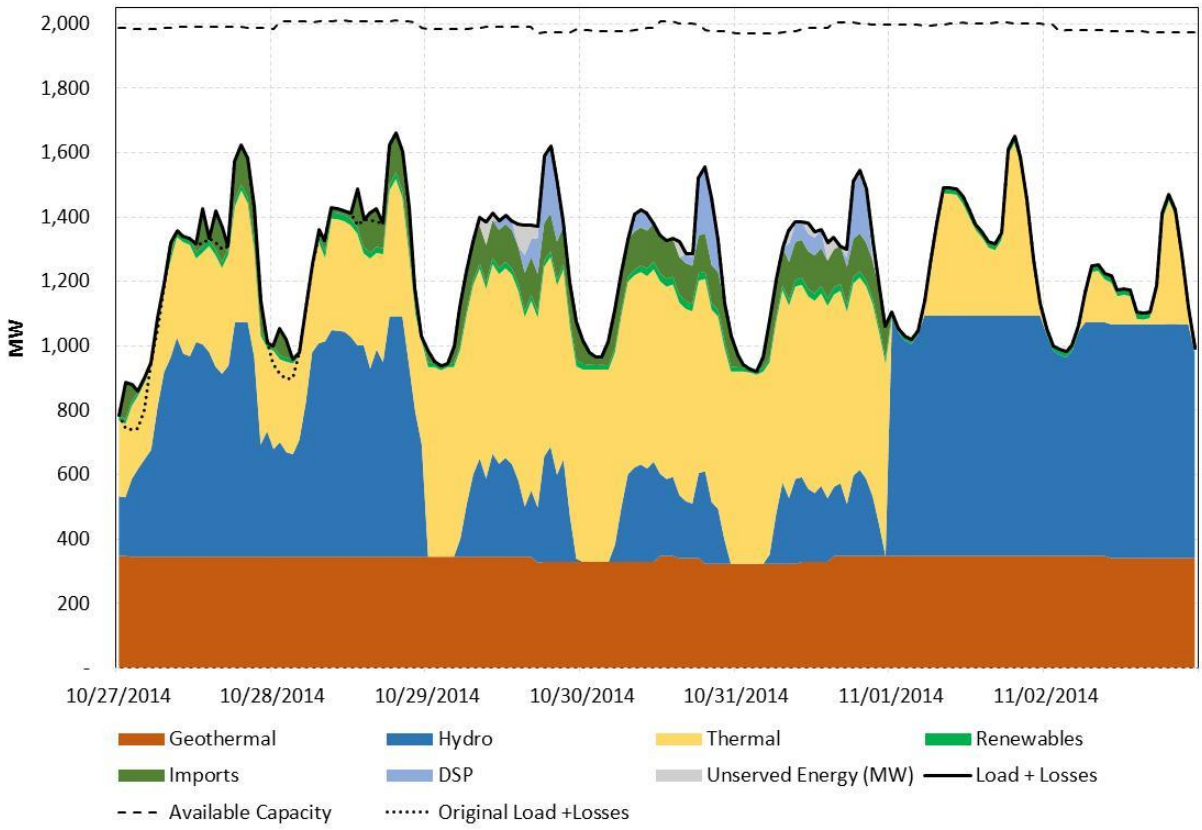

Fig. 14 Dispatch for one representative week (DSP program)

Meanwhile, in the case of the utility-scale renewable projects, the amount of USE actually increases which is due to a lack of sufficient system flexibility, in terms of ramp rates and commitment cycles, to respond to the intermittent nature of the renewable generation.

5.2.4. Overall system energy price

Overall, the system energy price (inclusive of the CoUE) is shown to drop significantly for the installation of SWHs and implementation of EE measures, mostly due to savings on USE. However, in the case of solar EG, the price actually increases while with industrial cogeneration it only decreases slightly. This is despite the apparent benefits in reduced fuel costs and USE. The reason for this upturn in price is due to energy sales decreasing while fixed cost components remain the same. Initially, savings due to fuel costs compensate for the rising fixed cost component, with the FiT of the EG still considerably cheaper than the SRMC of all thermal generation (as demonstrated in *Tab. 6*). However, as generation higher up in the merit-order is displaced due to higher penetration of these disruptive technologies. This is demonstrated for solar EG and industrial cogeneration in *Fig. 15*, where the annual output per generation type and system energy price are plotted aside one another for varying levels of penetration.

Tab. 6: Cost of generation (SRMC or Fit) and merit-order for different generation types

Position in merit-order	***Generation type***	***SRMC***	***FiT***
#		***$/MWh***	***$/MWh***
1	***Hydro***	3.7	-
2	***Biomass***[1]	15.0	-
3	***Geothermal***	30.0	-
4	***Thermal***	159.5 – 341.1	-
N/A	***Wind***	-	110.0
N/A	***EG (Solar)***	-	120.0
N/A	***EG (Cogeneration)***	-	100.0

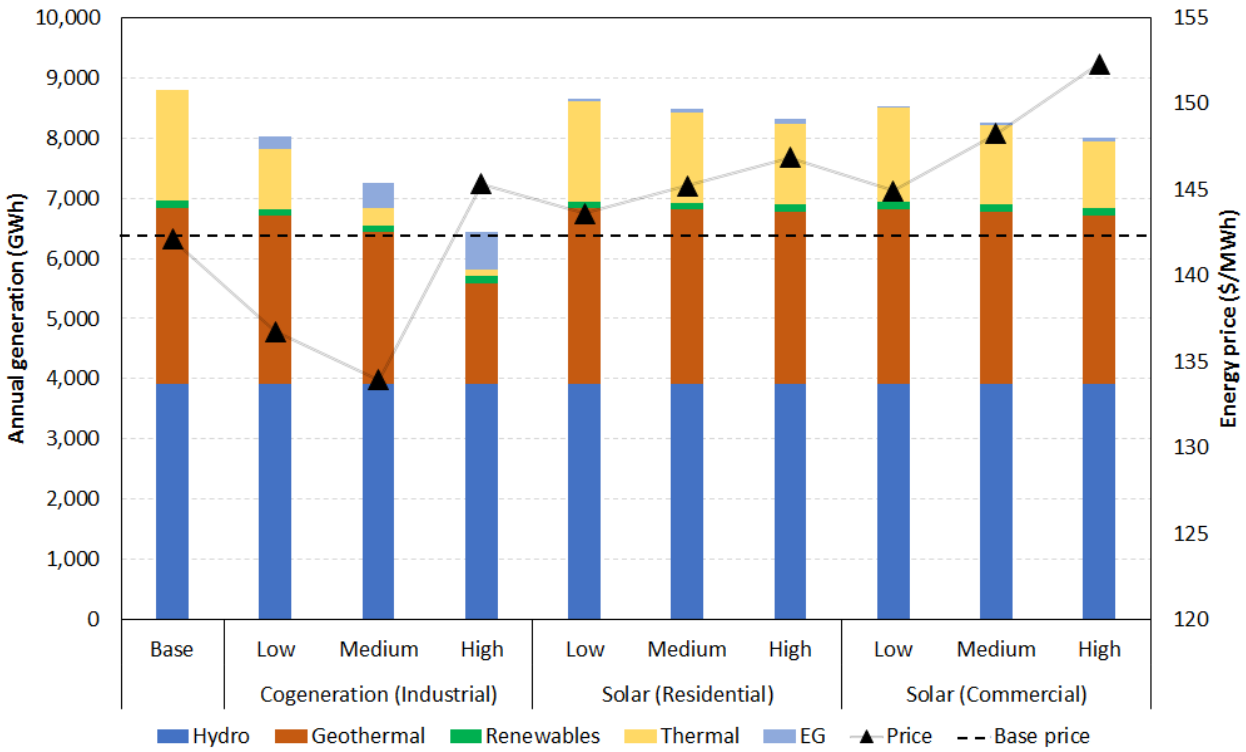

Fig. 15 Annual dispatch of generation and system energy price (without cost of unserved energy) for varying levels of penetration of EG

6. Conclusions

The adoption of novel and disruptive approaches/technologies has been modelled and shown to both provide benefit to the system but not without consequences on the unit price of energy charged to the end user. All presented technologies/approaches except utility-scale renewables and DSP present a reduction in total energy sales for KPLC. However, as existing generation and networks have inherent fixed costs, these need be recovered by KPLC leading to an increase in system energy price.

In the aforementioned cases where a drop in annual energy demand was observed, a reduction in the reliance on relatively expensive thermal generation resulted, reducing generation costs (mostly fuel) while additional costs due to FiTs for EG are incurred. In the cases where there is a reduction in peak demand (EE measures, SWH adoption, DSP and industrial cogeneration), system reliance on peaking capacity is also reduced, leading to a further reduction in generation costs and increase in system reliability.

Reliability is reflected in a reduction in USE on the system. This occurs in all cases except that of the utility-scale renewable plants. With industrial cogeneration, SWH rollout and EE measures, USE was completely removed while all other technologies enjoyed significant decreases in USE. The intermittent nature of utility-scale wind and solar PV resulted in an increase in USE as a result of insufficient system flexibility.

Overall, the system energy price has been shown to vary only slightly, within 5% across all disruptive approaches/technologies except for embedded solar generation in the commercial sector (7.4% increase). In the case of the adoption of EE measures, SWH rollouts and utility-scale solar PV; the system energy price dropped while solar EG, utility-scale wind and DSP had the opposite effect.

For all novel and disruptive technologies/approaches, there are both positive and negative impacts either in terms of system reliability or system energy price. Considering energy constraints across most of Sub-Saharan Africa, the increased system reliability should not be understated. The benefits of energy savings and peak demand shaving have been clearly shown. While the fixed cost portion of system energy price increases with the advent of novel and disruptive technologies/approaches, this is often offset by the reduction in other costs such as fuel costs. Additionally, the slight reduction in expensive fuel costs in Kenya will likely be significantly higher in other countries with higher reliance on thermal generation as a result of fuel cost savings.

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