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Optimising mixed-portfolio hybrid Renewable systems with no or constrained grid connectivity

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Abstract. We present a method to optimise a hybrid renewable energy system design under various grid constraints, from entirely off-grid to strongly interconnected. The optimisation procedure is a simplified downward gradient method, and the variable used as the objective function is the equivalent annual cost of the system installation and operation.

The results show how a good interconnection provides the opportunity to use renewable energy technology as an income stream without a need for energy storage. A balance of energy storage and local backup generation emerges as the optimum if the grid is severely constrained or without grid connection. It is always a balance of storage and backup, as the storage is most cost-effective to balance supply and demand over short time scales of less than a week while back-up generation is better able to meet longer periods of insufficient renewable generation. Another key results is that a combination of renewable technologies, PV and wind, is always better here than one technology alone.

Key words

Hybrid Renewable Energy System, off-grid system, constrained grid, optimisation

1. Introduction

While a rational design choice for a Renewable Energy system project with a good grid connection is fairly easily calculated and mainly based on the economic return based on the renewable energy resource alone, the situation is very different for a development opportunity with limited export capacity. Given the volatility of many renewable resources, in particular wind energy and Photovoltaics, a system design with an installed capacity to match the export limit would lead to a minimum solution which utilises the grid export opportunities rarely to their potential. Increasing the installed capacity would utilise the grid for export more frequently but would, at the same time, encounter progressively more instances where the onsite generation exceeds local demand and export capacity, leading to curtailment of the generation potential.

Considering the inflexibility of the generation from these kind of Renewable Energy Systems, adding flexibility to the system by demand-side management or energy storage, is a key to utilising the local resource most effectively. Demand-side management can only shift demand by a relatively short time-frame but energy storage can, depending on its storage capacity, balance generation with both, local consumption and export opportunity, over a longer time frame. Substantial energy storage is often the most expensive single component in a hybrid energy system and, to get the most benefit from the investment, must be carefully sized and operated [1].

Many optimisation approaches have been developed to optimise an energy system. One common approach is to balance supply and demand at every time step (typically every hour or half-hourly) over an analysis period (typically a year). The measure of how well the system is designed is encapsulated in an objective function which is often a cost measure. For a trial configuration of the generation and storage portfolio, this objective function is then evaluated on the basis of the size of the components (e.g. investment and maintenance) and the usage of the components (e.g. fuel costs or component ageing). In the optimisation, the minimum of the objective function is sought, subject to the constraints that the system balances and that components work within their operating limits.

One class of main approaches consists of downward-gradient methods, such as Mixed-Integer Linear Programming [2] which have the advantages of being robust and converging usually reliably and rapidly to a maximum. Disadvantages are the implicit assumption of a single global minimum as well as the representation of the supply-demand balance as a large set of individual constraints, leading to a high-dimensional system with consequent requirements on computer memory. Some alternatives use types of genetic algorithms [3]. One key advantage of these methods is that, by using ensembles of trial solutions, they are likely to find a global optimum in complex cases where many local minima may exist due to the nonlinearity of the system. Apart from the complexity of implementing such approach (although many computing packages offer such optimisation tools as add-ons), these methods are also computationally expensive.

Here we develop and apply an approach in which we separate the energy balancing and optimisation steps as far as possible. The main optimisation stage is implemented as a forward-search starting with a reasonably good configuration and exploring the configuration space in successively refined steps. After identifying the best renewable device, the main optimisation searches for the best combination of renewable devices and energy storage. Within that search, the energy balancing is separated into first the non-dispatchable generation, then the storage utilisation, and finally the balancing using the remaining options. The best backup generation is solved in a separated step within the main optimisation by comparing the cost of backup generation against penalties incurred from loss of supply. The optimisation moves through the possible solution space guided by comparing trial configurations and to interpolate or extrapolate the search steps. By comparing a discrete set of results, an implicit requirement is that the solution space is fairly smooth and that the number of local minima is small, but an extensive initial survey showed that this requirement is met, at least in the typical types of hybrid systems investigated here.

The algorithm is described in section 2, while the test case to which the algorithm is applied is presented in section 3. The results are presented in section 4, followed by the Discussion and Conclusion in section 5.

2. Balancing and optimisation algorithm

In this section, the energy balancing of meeting demand by a combination of locally generated Renewable Energy, energy storage, local back-up generation, and import or export to the wider grid is introduced in 2.A. As with all iterative solution processes, a sensible initial trial configuration needs to be set as the starting point for the optimisation. The process to determine this starting point is presented in 2.B, followed by possible objective functions available as the optimisation criterion in 2.C and the optimisation algorithm itself in 2.D.

A. Energy balancing

As with all energy and power systems models, the balancing of supply and demand is a key requirement. We start with a set of aligned time series of energy consumption and the local resource with a sampling time step of *dt*. We denote the consumption by *L*, inspired by the fact that the consumption divided by *dt* is equal to the average load over that period. For the case investigated here the resource is in the form of wind speed and global horizontal irradiation data, leading to wind energy and Photovoltaics (PV) as potential local generation types. In the first step, the resource is converted to electricity production from unit generators in that time step, p_P and p_W (or more generally p_i i= 1, 2…M_G for M_G forms of available resource). The 'unit' could be a generic unit device (with rated or peak capacity of 1 kW), or it could be a specific device (e.g., a 12 kW wind turbine with a particular performance curve, which is then converted to a 12 kW*dt* unit device).

Having converted both, the consumption and the resource, into a common unit (usually kWh), the available components are considered in a hierarchical order, starting with the onsite renewable generation, followed by considering the storage component, then the grid connection, and completed by the 'back-up generation'. Depending on the conditions, it is obviously possible to change the order.

For a generating portfolio of N_i renewable devices, the use of the onsite generation against the consumption leads to a time series of the residual demand, *R*:

$$\boldsymbol{R_1(t) = L(t) - \sum_{i=1}^{M_G} N_i\, p_i(t)} \tag{1}$$

If $R_1 > 0$, the renewable generation is insufficient to cover consumption, and the user needs to use the storage device, import electricity from the grid, or use any available back-up generation.

Conversely, if $R_1 < 0$, then renewable generation exceeds consumption and one could either charge the local storage device or export the surplus to the grid. Any surplus remaining after charging or exporting will have to be counted as curtailed.

The next step is to consider the storage element, which is broken down into three steps; first a decision-making step as to whether and to what degree, to use the storage element, secondly to calculate the response of the storage element subject to its constraints, and thirdly the outcome of the storage action in terms of effects on the system balance and state of charge of the storage.

The choice of the system as to whether to activate the storage device can depend on a variety of available information, certainly the State-of-Charge, *SoC*, but could also evaluate current and projected electricity prices for the import/export option. If the main purpose of the storage element is to balance the system, then the storage will be asked to match the residual load, R_1. However, if it also serves an economic function, such as importing cheap off-peak electricity and selling expensive peak electricity, it may be advantageous to import more electricity than is needed to balance the system, or vice versa. To allow both cases, a storage load, L_S, is defined. If the purpose is only to balance the system, then $L_S = R_1$.

If the decision has been made to invoke the storage element, then the residual or desired balance is met by N_S storage units subject to the power rating of each unit, $G_S^{\pm}$, energy rating, E_S, and minimum state of charge, E_{min}. If the balance is positive, the storage element is asked to provide the balance up to the remaining charge and the power rating of the device. If the storage element is asked to provide L_S, then the response, P_S, can be formalised as

$$\boldsymbol{P_S = \min\left\{\begin{matrix} L_S \\ N_S G_S^+ \\ (SoC - N_S E_{min})\eta_D \end{matrix}\right\} ; L_S > 0} \tag{2}$$

Conversely,

$$\boldsymbol{P_S = \max\left\{\begin{matrix} L_S \\ N_S G_S^- \\ \frac{1}{\eta_C}(SoC - N_S E_S) \end{matrix}\right\} ; L_S < 0} \tag{3}$$

After having calculated the energy exchange to or from the storage device, its state of charge is updated as

$$\boldsymbol{SoC(t) = SoC(t-dt) + \left\{\begin{matrix} \frac{1}{\eta_D}P_S & ; P_S > 0 \\ \eta_C P_S & ; P_S < 0 \end{matrix}\right\} - \delta_S} \tag{4}$$

where η_D is the discharge efficiency, η_C is the charging efficiency, and δ_S the self-discharge rate. The residual balance is then updated to

$$\boldsymbol{R_2(t) = R_1(t) - P_S(t).} \tag{5}$$

The next step is to meet the residual demand from the grid or to export surplus, up to the capacity of the connection. The grid interchange, I, is calculated as

$$\boldsymbol{I = \begin{cases} I_{max} & ; R_2 \geq I_{max} \\ R_2 & ; I_{min} < R_2 < I_{max} \\ I_{min} & ; R_2 \leq I_{min} \end{cases}} \tag{6}$$

followed by $\boldsymbol{R_3(t) = R_2(t) - I(t).}$

This final residual balance can then be attributed variously to back-up generation or loss of generation, if it is positive. A negative final residual balance implies surplus energy which either has to be curtailed or could be available for other, not-yet identified uses.

B. Initial configuration

To ensure that the solution is found within a reasonably small number of iterations, a sensible initial configuration has to be chosen. One option which has worked well is to start with an initial portfolio where each renewable resource produces an equal share of the local annual consumption.

Setting an initial storage size can be based on the typical scenario in which there is a clear break in required storage size between balancing daily fluctuations compared to storing energy for over a week. For the cases tested here, an initial size half of the mean daily consumption was chosen. In addition to determining the initial configuration, also the initial search steps have to be defined. These can be set as the mid-point between the initial value and the lower or the upper limit, respectively.

C. Objective functions

Depending on the criterion used to evaluate a proposed portfolio of generation and storage, a variety of objective functions to be minimised could be used, ranging from a purely economic measure, such as Simple Payback Period (*SPB*), Internal Rate of Return (*IRR*), or Net Present Value after a set period (NPV_P). As energy provisions to a community are not usually investment projects with a fixed life span, the equivalent annual cost *(EAC)* might be more appropriate [4]:

$$\boldsymbol{EAC = \sum_i \left(\frac{C_{C,i}}{A_{T_i,r}} + C_{O,i}\right) - C_{E,ex} + C_{E,im} + C_{Pen}} \tag{7}$$

where

- C_C is the capital cost for technology i which includes the onsite renewable generation devices, storage components, and back-up generation to meet the final residual demand;
  $i = \{1, \ldots, M_G, S, B\}$ where B represents the final component met by backup generation.
- $\boldsymbol{A_{T_i,r} = (1-(1+r)^{-T_i})/r}$ is the present value of the annuity factor for a technology with a life time T_i and an annual interest rate of r.
- C_O are the operating costs, including maintenance and fuel costs, for technology i.
- $C_{E,ex}$ is the income from exporting electricity.
- $C_{E,\mathrm{im}}$ are the costs of importing electricity.
- C_{Pen} is a penalty for any demand not met.

If the objective is to maximise self-sufficiency, then the magnitude of grid exchange, $\boldsymbol{\sum_t |I(t)|}$, could be minimised. Another option could be to minimise the carbon footprint of the system.

D. Optimisation

Based on the initial survey, a search is proposed which is based on comparing the value of the objective functions of the current portfolio with that where one of the parameters to be optimised is changed by a discrete step up and down, where the three parameters adjusted for the optimisation are the number of PV panels, wind turbines and storage units, $\{N_P, N_W, N_S\}$. After the evaluation of changing one parameter, the best choice of these three options is used to evaluate benefits from changing the next parameter and so on. The optimum backup generation is determined not as a free parameter but as a function of the current value $\{N_P, N_W, N_S\}$ and the costs of backup generators or incurring a penalty for not meeting demand.

For the next trial sequence, the step size is halved (and rounded up) so that the search space is incrementally refined. Once none of the parameters have changed through a full trial cycle and the minimum step size of one unit in either direction is reached, that solution was returned as the ‘optimum’.

3. System for case study

The demand data were half-hourly consumption data from a small community in Scotland with a mean consumption of 275 kWh per half hour (or annual consumption of 4807 MWh). As it is a small community, the demand is highly variable as shown for four representative days in Figure 1, with a consumption of less than 573 kWh for 99% of the time but a maximum peak consumption of 665 kWh. The daily consumption varied from 3 MWh for low-season weekend consumption to around 24 MWh during peak season. It is assumed that the community has subscribed to a time-of-use tariff, with a minimum night-time electricity price of 8p/kWh, and standard day tariff of 8.8p/kWh, but peak prices up to 40p/kWh depending on the season.

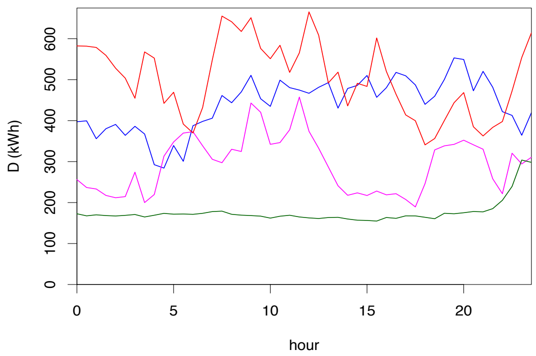


Fig. 1. Half-hourly consumption data for four typical days.

The renewable resources considered here were medium-sized wind turbines and fixed-tilt PV panels, where the resource data were obtained as hourly wind speeds and global horizontal irradiation from the UK Met. Office through the British Atmospheric Data Centre [5] for the year 2016. Both were interpolated to align with the demand data and then converted to unit device outputs using typical wind shear exponents for a neutral atmosphere and the performance curves for a Vestas V47-660, similar to [6]. The irradiance data were combined with a view factor to include the panel tilt and a linear response of the PV panel to the incident irradiance. A 1 kWp PV panel could produce 1914 kWh in that year, and the 660 kW wind turbine could produce 1700 MWh. Each of the technologies was allowed to install up to 4 MW, respectively. In addition to income from exporting electricity at the current tariff, electricity generated by PV or Wind and either used locally or exported, also attracted Feed-in-tariff at the rate valid for the UK for July 2017.

The onsite renewable generation was then complemented by a number of generic Li-Ion batteries (in units of 100kWh/100kW with a roundtrip efficiency of 90% and a self-discharge rage of 1% per day), a constrained connection to the grid, and onsite diesel generators (in units of 100 kW each).

The objective function used here is the equivalent annual cost, *EAC*, as defined in eq.(1) where an interest rate of 5% was assumed, a 30-year life of a PV panel, 20 years for a wind turbine, 5000 cycles for the battery, and a lifetime of the diesel generator of 20,000 operating hours.

In this study, the effect of imposing a varying constraint on the import or export capacity was studied. We considered cases where the constrained was applied equally to power flows in both directions, but also cases where either only the import or only export constrained was changed while the reverse power flow was either unlimited or completely prohibited; the cases of varying import limit with either no export or unlimited export, and the cases with equal limits, as indicated by the shaded cells in Table I.

Table I. – Grid constraints investigated.

	Export Limit (kW)					
Import limit (kW)		0	100	200	1000	∞
	0	🟩	🟩	🟩	🟩	🟩
	100	🟩	🟩			🟩
	200	🟩		🟩		🟩
	1000	🟩			🟩	🟩
	∞	🟩	🟩	🟩	🟩	🟩

4. Results

Figure 2 shows the progress of the optimisation by showing the interim values of *EAC* as the optimisation loop progresses through its iteration. In all cases highlighted in Table I, the interim *EAC* decreased initially rapidly, followed by a much slower approach to the final solution within a total of 10 to 12 iterations. Figure 3 shows the breakdown of the costs for the different system components as the grid constraint for import and export is increased (the diagonal in Table I). The last column shows the current annual electricity bill for that community. The pink shows the income or expenditure for the electricity consumption or export. There is a small income even in the off-grid scenario from the Feed-in-tariff. As export becomes available in sufficient quantities, the ability to sell green energy to the grid becomes an attractive income stream. At the same time, the need for storage and backup generation reduces. Despite the few instances of very high peak demand, it was economically more advantageous to install sufficient diesel generators than incur a penalty for loss of supply, except in the case where the import limit at 1000 kW was only a little below the peak demand (1330 kW equivalent to 665 kWh), where 4000 kWh of demand were not met over the year.

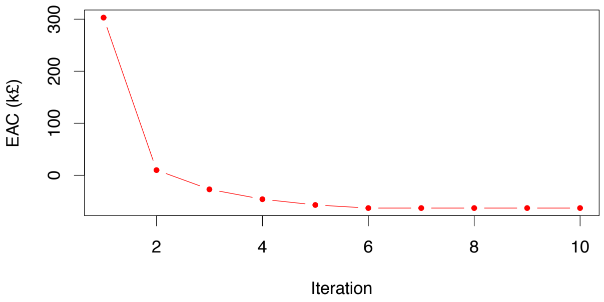


Fig. 2. Cost for system with equal constraint of ± 1 MW during optimisation from initial configuration to final ‘optimum’.

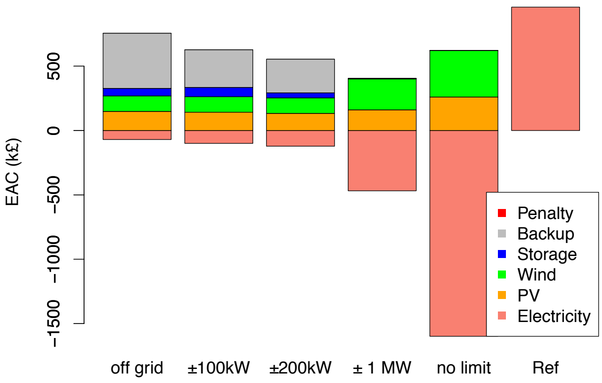


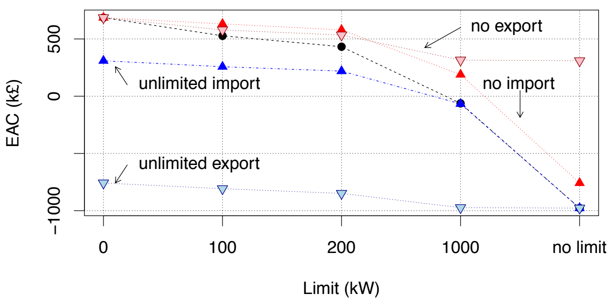
Fig. 3. Cost breakdown by technology and expenditure/income type from off-grid through various import/export limits to unlimited grid connection. The Reference case shows the current annual electricity bill.

Figure 4 summarises the final configuration against the variable limit, where the circles indicate equal import and export limits, while the upward triangles refer to a varying export limit and the downward triangles to an import limit. The red symbols correspond to those where there is no possibility for power flow in the other direction while the blue symbols are those for free power flow in the other direction. As one might expect, the equivalent annualised cost in Fig. 4a decreases as the import/export limit is relaxed. It is also not surprising that the case of equal constraints is in between those where one direction is unlimited and those where power flow in one direction is not possible at all. Comparing the cases where one direction is unconstrained (the blue triangles), it is clear that the cost is always negative if the export is unconstrained (light blue), resulting in the investment in onsite generation as an income stream. Allowing free import but constraining export (dark blue), only provides a slight reduction in costs compared to the symmetric case. Conversely, the equivalent annual cost is only marginally affected by the import limit if no export is possible.

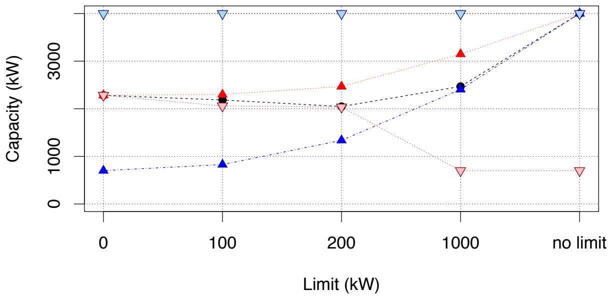
Figures 4b and 4c reflect the fact that onsite generation can be a productive income stream if unrestricted electricity export is allowed. In those cases, the optimum solution always converges to the maximum installed capacity allowed. In the converse case of no export but unrestricted import (dark green upward triangle at 0 limit or red downward triangle at no limit), the optimum solution included only a single wind turbine and a comparable amount of installed PV capacity. However, the optimum solution still includes onsite renewable generation to offset some of the electricity costs effectively, together with some batteries of a storage capacity comparable to the PV peak capacity (700kWh/700kW for 700kWp) while there is no need to install any backup generation (Fig. 4d and e).

As either both restrictions are relaxed simultaneously, or as the export restrictions are lifted when import is always unrestricted, the installed capacity gradually increases, where the difference between the PV and Wind is due to the different size of the unit device (modular 1 kWp panels versus individual 660kW machines). However, prohibiting

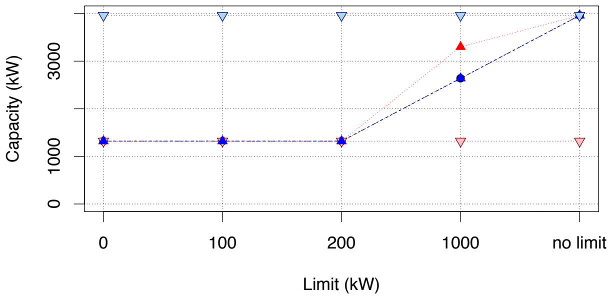
a) *EAC*



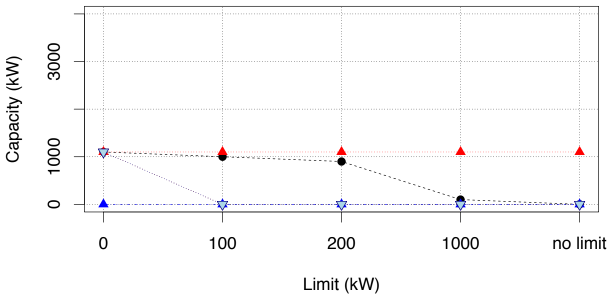
b) installed PV capacity



c) installed Wind turbine capacity



d) Diesel generator capacity



e) Battery capacity

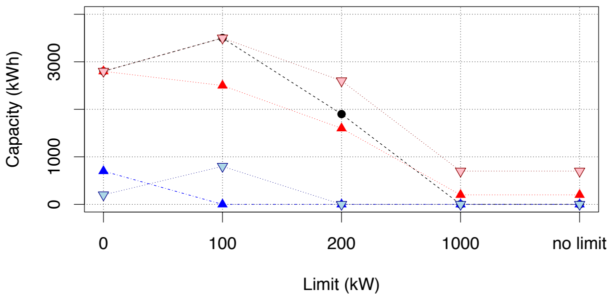


Fig. 4. Summary of optimum hybrid configurations for different levels of grid constraint. Circles for equal import/export constraint. Upward triangles for export, downward triangles for import; red for no reverse power flow, blue for unlimited reverse power flow opportunity

electricity export shifts the economic case away from installing more capacity in favour of importing more electricity, leading to a reduction of the installed capacity to a level where the onsite generation produces in a year about 110% of the local consumption.

Given the nature of the two available natural resources, the backup generation capacity (in Fig. 4d) is always sized to meet peak demand if no electricity can be imported but rapidly drops to zero if electricity can be imported from the grid to meet any shortfall from the PV and wind. Likewise, there is no economic case for using storage (Fig. 4e), even with current time-of-day tariffs, which would allow to buy cheap night-time electricity and sell it back at peak time. However, a constraint in any one direction makes installation of at least some storage advantageous. The highest energy storage solution is found for a severely constrained two-way connection or a severely constrained import but no export possibility. The economic argument for this lies in the balance between the running costs of the diesel generator and the costs for the battery.

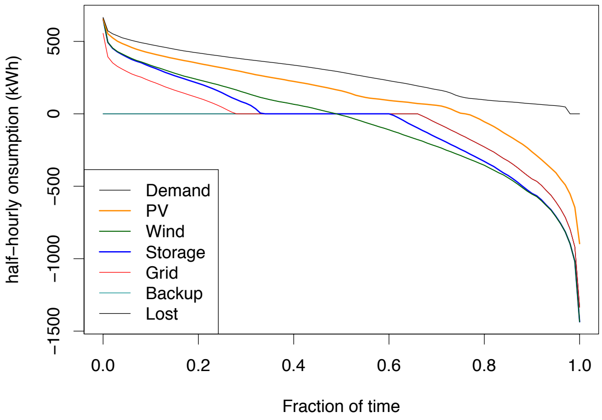


Fig. 5. Residual load duration curves for grid connection limited to ± 200 kW.

Figure 5 illustrates the response of the system to the installed capacity for the case of equal import/export to a limit of ± 200 kW as residual load duration curves, with the top black line showing the load duration curve from the demand. The next line is the residual load after usage of PV. Where the residual load duration curve crosses the zero line, it indicates that the PV panels produce more electricity than is locally used. The next (green) line is the residual load after using wind power. The use of the storage is mainly to balance the system at intermediate load conditions, such that there is zero residual load for a substantial part of the time (26%). The limited grid connection increases this to 38%, with 28% of the time showing residual load and 34% of time surplus generation which cannot be used. The diesel generators then supply the remaining residual load, in particular the maximum peak conditions.

A sensitivity analysis for equal constraints, changing either the irradiance or wind speed by ±10%, changed the *EAC* by less than £100k in the constrained cases but by up to £250k in the unconstrained grid. The required back-up capacity was not affected while the optimum number of PV, Wind, and storage units changed by an amount comparable with the percentage change in the resource.

5. Conclusion

We have presented a low-cost optimisation procedure and applied this to designing a hybrid energy system consisting of two types of renewable generation, energy storage, backup generation and a limited grid connection, where the effect of the grid connectivity was investigated as the varying factor.

The main results are that in all cases the optimum configuration consisted of a blend of both renewable types, PV and wind, and never just one of the two resources. Furthermore, the ability to export surplus electricity strongly determined as to whether the system consisted only of a large number of renewable devices which then provide an income stream, or a blend of renewable and backup generators with energy storage.

At present, the optimisation was driven by a simple direct economic objective function, namely the equivalent annual cost, but future work will expand this to include consideration of other factors, such as carbon emissions, self-sufficiency, or local societal factors. Furthermore, the effectiveness of Demand-Side Management schemes will be explored in future work. This paper considered the optimum system design, but future work will investigate if the approach can also be effectively applied to the operation of an installed system.

Acknowledgement

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