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At which scale should electrical storage be installed? A comparison of storage systems for households and communities with renewable generation.

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Abstract

This study investigates how best to deploy small scale electrical storage, in conjunction with domestic renewable generation. It explores potential advantages and disadvantages in installing storage on a communal, as opposed to on an individual household basis.

Previous research has found that installing electrical storage too expensive to be viable, if electricity can be exported in return for payment. This study assumes a context of domestic renewable generation, with *no payment for any electrical exports*.

The study used typical UK patterns of domestic electrical demand, using high resolution synthetic data, and assumed generation from photovoltaic panels on the roof top. Several different scenarios were studied, including high-density urban housing, more spacious rural-type housing, and different electrical demand profiles. A tool was created, which modelled excesses and deficits in electrical generation, with and without storage, for individual households, and aggregations of households, over a single summer and winter day. The study also included a brief investigation of different temporal resolutions, and a case study which compared synthetic electrical demand data with measured electrical demand data from the village of Findhorn.

It was found that storage, and aggregation, both individually and in combination, do improve matching of supply and demand, and reduce the quantity of electricity drawn from the grid. Installation of *minimal* quantities of storage (quarter of a *Tesla Powerwall* or equivalent) brought the best financial benefits compared to capital costs: annual revenues of up to around £100/yr. for storage on an individual basis, and up to around £200/ yr. when storage is installed in combination with aggregation (at current tariffs). These revenues are considered sufficient to justify capital expenditure on some types of storage, even at current prices, though significant payback times (~10yrs) are still likely. Increasing quantities of storage brings greater revenue, but with “diminishing returns”, and much higher capital costs.

Practical advantages and challenges of installing community-based storage systems were considered, as was the potential for additional financial and other benefits of storage, beyond those studied in this project.

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1. Introduction

The thesis explores aspects of electrical storage. It aims to compare the benefits of storage, alongside renewable generation, on different scales, in a UK context.

As the UK, other EU member states, and many other countries have committed to reducing CO_2 emissions, policies have been implemented to increase the share of low-carbon forms of electricity generation, including from renewables [1-3]. The share of renewable generation has risen considerably in recent years. [3] While much generation is from installations in the MW range [4] there has also been installation of community and domestic scale systems, such as small and medium wind [5], and photovoltaic panels, including many on domestic roofs [3].

Traditional systems of electrical power generation and delivery incorporate despatchable generation, such as some types of gas-fired power plant, to ensure that varying demand for electricity is always met, and stability of the grid is maintained [6]. As the penetration of renewable generation increases, maintaining stability becomes less straightforward. It is well documented that many renewable energy sources are intermittent, and that peaks in generation often do not coincide with peaks in demand. Thus maximising the use of renewable energy resources, while maintaining stability, on an electrical grid with high penetration of renewables, inevitably brings challenges. There are numerous approaches to dealing with such challenges, including: installing peak power plant capability [7-9], installing "smart" systems, such as demand side management[10] / active network management, and incorporating additional storage into the electrical system [11, 12].

For a domestic or small-scale generator of electricity, at present, others have concluded that it does not make financial sense to install storage, when electricity can be freely exported to the grid, at all times, and in return for payment [13], particularly if Feed in Tariff payments [14] are significant. The majority of companies selling photovoltaic panels to the UK domestic market, for example, do not even offer any kind of storage system[15], according to consultants Delta Energy and Environment, and costs of storage systems are considered too high to be of interest to the mainstream UK domestic market at present [15, 16]; however the authors of this consultant's report believe this situation will soon change.

It is in locations with significant grid constraints where storage and microgrid solutions have been most actively explored. The implementation of storage and other "smart" systems is primarily in areas with no or weak connections to the grid, such as Eigg [17], Gigha [18], Orkney [19, 20], and rural Argyll [21], in Scotland, and island or other remote locations in other countries, e.g. [22, 23].

Storage can bring benefits for different parties in the electrical networks, including distribution network operators, generators and consumers. The UK grid currently has around 3GW of large-scale storage, primarily from pumped-hydro stations in Scotland and Wales [24]; it is widely recognised that greater quantities of storage would be beneficial [25]. The Carbon Trust and partners at have published reports on the economic value of storage systems, at grid scale, under different scenarios [11, 12, 26]. An example of storage in a location with good grid connections is a 6MW / 10MWh demonstration plant in Leighton Buzzard, East Anglia (England), built primarily to defer upgrades to distribution networks [27]. Ratnam et al discuss potential of distributed storage alongside photovoltaic generation, for the benefit of distribution networks in an Australian context [28].

Recent developments in some storage technologies, reductions in costs, and increasing penetration of renewables, are drivers to increase the quantity of storage on networks. This thesis examines some aspects of how small-scale electrical storage might best be deployed, in a distribution network with renewable generation.

2. Objectives and scope

2.1. Objectives

This study is in the context of renewable domestic or communal electrical generation. It examines the effect of implementing electrical storage, at different scales of system. The study attempts to answer some basic questions:-

- Is it worth a householder installing *electrical storage*, together with renewable generation, and if so, how much and of what type?
- Is it worth an individual household *working together with neighbours*, to make an *aggregated renewable energy system*? If so, what are the pros and cons of smaller and larger sizes of communal system?

2.2. Scope

This study examines rooftop photovoltaic generation only, in both high-density urban, and less dense rural / suburban housing environments. Photovoltaic generation was chosen as this is considered the most feasible renewable source of domestic or local small-scale generation in a densely-populated urban environment, where effective wind generation would be limited by lack of space, close proximity of residents, and relatively low wind speeds and turbulence in the urban environment. Clearly, in some rural locations, other types of renewable generation, such as wind or micro-hydro, will be realistic, and may be better options.

This study looks at the climate of one location only, Glasgow. It aims to study examples of typical *current* patterns of electrical demand. Future demand patterns, which could be expected to include electric vehicles and heat pumps, were not specifically included, though some brief discussion is made.

Regarding electrical connections, it is assumed that all houses are connected to the grid. This assumption is made because it is the case for the vast majority of housing in the UK.

However, scenario is adopted regarding the financial context: **that there is no "feed-in tariff", and even, no payment is made for export to the grid**. This assumption is made in the context of sharp reductions in UK Government support for renewable generation [14], a trend which, at present, shows no sign of being reversed. One exception to this rule, a scenario in which one could export electricity *at peak times only,* is very briefly considered.

This study does not investigate demand response measures. It briefly considers time of use tariffs, i.e. varying electricity prices during the day. In a future smart grid, especially one with high penetration of intermittent renewable generation, it is likely that varying tariffs may be used as an incentive to encourage shifting of demand to times when generation is plentiful and cheap, and to reduce demands at times of peak demand, or when it is expensive to produce electricity [10]. Such study would be a useful extension of this project

This study does not cover either direct solar thermal systems, other types of renewable generation, or thermal storage, due to constraints of the project.

This project only investigates possible benefits and costs of different storage schemes to the individual household, and where applicable, the community. It does not consider possible benefits and costs to the electrical network. Thus, additional services which storage could potentially offer to the grid, such as voltage stabilisation and fast frequency response [12], are out of the scope of this project.

Finally, this project only discusses the energy contribution of storage in terms of reducing the need to draw electricity from the grid. It does not include the energy used to manufacture, transport, or maintain storage devices, nor that associated with their re-use, recycling or disposal at the end of their operational lives, or any other associated environmental issues.

3. Literature review

3.1. Background: how best to utilise small-scale renewable generation

Wildi (1991) [6] and Abu-Sharkh et al (2006) [29] describe traditional electrical network, in which large scale generation sources are connected to *transmission networks*, which operate at high voltages to minimise losses. Near to sources of electrical demand, the transmission networks connect to a substation, where the voltage is stepped down to medium or low voltage. Out of the substations, lower voltage networks, called *distribution networks*, convey electricity to consumers.

Renewable generation can be installed at a wide range of scales: from large scale hydro schemes, to micro generation at a community or household scale [29]. Abu-Sharkh et al [29] state that it is usually practical and economic for smaller renewable generators to connect to distribution networks, networks which were never designed for such types of connections[29-31], and which Schwaegerl and Tao (2014) [30] and Lopes et al (2007)[31] describe as "passive" or "dumb". Schwaegerl and Tao [30] note that electricity systems have always been "smart", but that the control systems have been on transmission, not distribution, networks.

Lopes et al [31] describe the opportunities and challenges presented by *distributed generation*, that is, small-scale generation connected to distribution, rather than transmission networks. The authors describe numerous drivers to increase distributed generation, which include national and international agreements to reduce CO_2 emissions, and thus encourage electricity generation from renewable sources. Other drivers include: potential opposition to new large power stations and transmission infrastructure on environmental grounds (e.g. concerns about visual intrusion); "commercial drivers", i.e. it may be easier to raise finance for smaller scale energy generation schemes than traditional large power stations; and having generation closer to sources of demand may reduce costs of network reinforcements and improve reliability of supply. The authors also cite "national / regulatory drivers" which may encourage diversification of energy supply in order to improve energy security, and seek the most cost-effective approaches to supplying electricity.

The authors go on to cite challenges: technical, commercial and regulatory, to the expansion of distributed generation. Describing a case study in Portugal, and citing examples from a UK regulatory context, the authors describe the importance of moving away from a "fit and forget" approach to installing renewable (or other) distributed generation, and the need for active network management:

"Active distribution network management is seen as the key to cost effective integration of DG [distributed generation] into distribution network planning and operation. This is in direct contrast to the current connect and forget approach." [31]

Schwaegerl and Tao [30] make similar arguments. They cite potential environmental and financial benefits from "smarter" distribution networks:

"In summary, distribution grids are being transformed from ***passive*** *to* ***active networks****, in the sense that decision-making and control are distributed, and power flows bidirectional. This type of network eases the integration of DG [distributed generation], RES [renewable energy sources], demand side integration (DSI) and energy storage technologies, and creates opportunities for novel types of equipment and services."*

The authors go on to state that such networks *"require the implementation of a radically new system concept"* and they believe that ***microgrids*** "*are perhaps the most promising, novel network structure."* [30] Abu-Sharkh et al [29] state the potential, in their view, for microgrids to deliver significant CO_2 savings.

Studies on microgrids

While this study is not specifically about microgrids, it is about "smarter" local networks, which could play a part in future microgrids. Thus, some discussion on microgrids is considered appropriate.

Abu-Sharkh et al [29] define a microgrid as follows:-

"A microgrid is a small-scale power supply network that is designed to provide power for a small community."

Schwaegerl and Tao [30] state the following definition of a microgrid:

"Microgrids comprise LV distribution systems with distributed energy resources (DER) (microturbines, fuel cells, PV, etc.) together with storage devices (flywheels,

energy capacitors and batteries) and flexible loads. Such systems can be operated in a non-autonomous way, if interconnected to the grid, or in an autonomous way, if disconnected from the main grid. The operation of microsources in the network can provide distinct benefits to the overall system performance, if managed and coordinated efficiently."

Schwaegerl and Tao [30] and Kroposki et al (2008)[32] describe the main components of a microgrid: one or more sources of generation, one or more sources of electric load, and of crucial importance, control systems. Kroposki et al take the view that incorporating some kind of electrical energy storage in the microgrid is highly desirable, and Schwaegerl and Tao state storage is, in fact, necessary.

Schwaegerl and Tao [30] give a very clear description, with examples, of what is and is not a microgrid. The authors give examples of microgrids several scales: a "*low voltage grid"*, (Figure 1) which comprises of several feeders connecting to demand (from housing and businesses), and other feeders connecting small-scale renewable sources; and "*a low voltage feeder*", which is a few streets with PV generation and demand Figure 2.

Figure 1 Microgrid as a low voltage grid. Schwaegerl and Tao, 2014 [30]

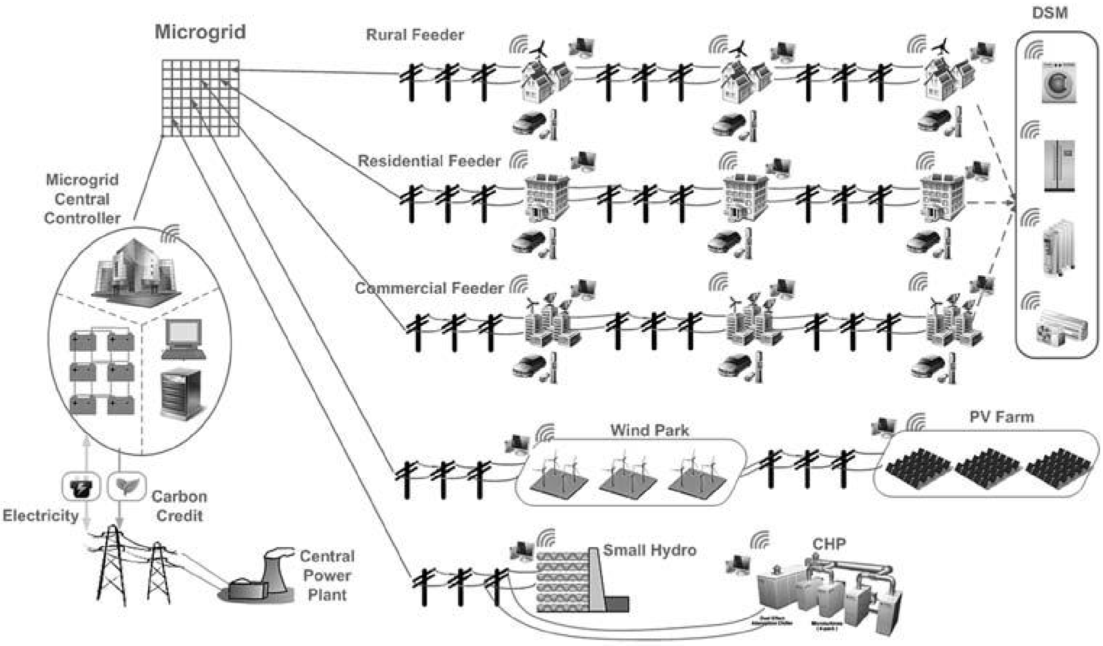
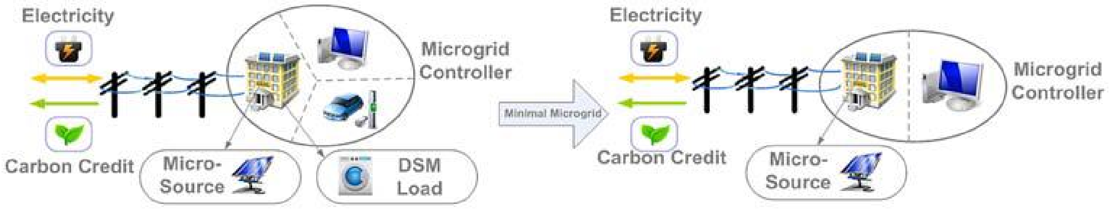


Figure 2 Microgrid as a low voltage feeder. Schwaegerl and Tao, 2014 [30]

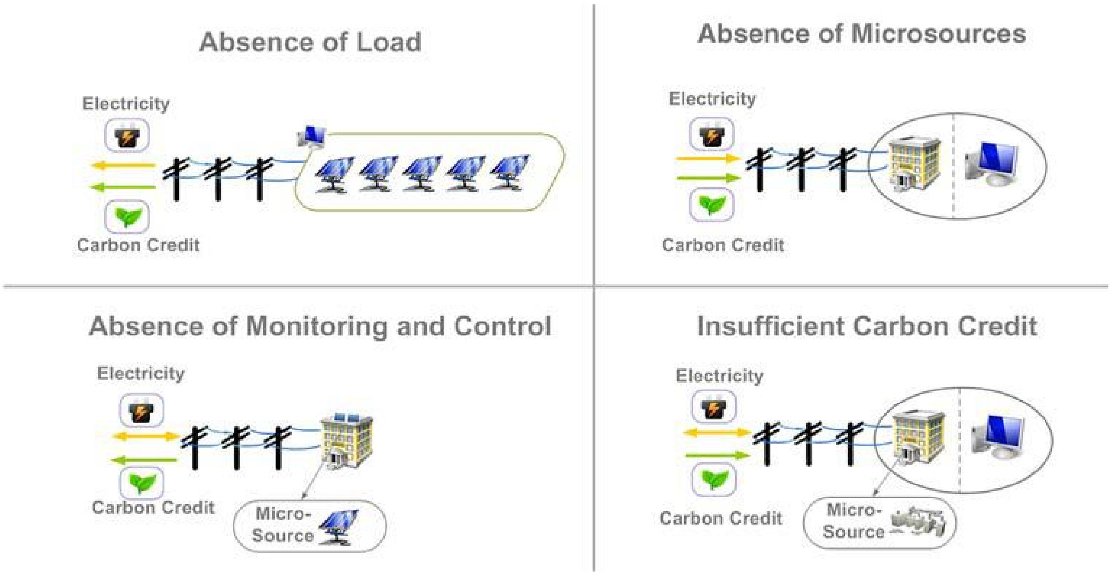
They quote an example of a *"minimal microgrid"*, which is an individual house, with a micro-source of generation, and flexible demand (Figure 3).

Figure 3 Microgrid as a low voltage house. Schwaegerl and Tao, 2014. [30]



Examples of what is *not* a microgrid include: networks missing either generation or demand, and networks with both generation and demand, but, crucially, without control systems (Figure 4). A very common example of such networks are solar photovoltaic panels, on rooftops, which feed into the property and the grid, but without control systems, an arrangement which has been termed "fit and forget" [30, 31].

Figure 4 What is not a microgrid? Sample cases. Schwaegerl and Tao, 2014 [30]



Abu-Sharkh et al [29] believe that, although microgrids have the potential to bring economic benefits, and to play a major role in reduction of greenhouse gas emissions, the concept was not (at time of writing) being actively explored by UK Distribution Network Operators (DNOs) because it is not in the interest of DNOs to do so: the report authors state major changes to the UK electricity market and its regulatory structure are needed for this situation to change.

3.2. An investigation into local renewable generation for domestic users, in a UK context: Abu-Sharkh et al (2006) [29]

Abu-Sharkh et al investigate give a detailed examination of the potential for local renewable generation, combined with a fossil fuel source in a combined heat and power (CHP) generator, connected within a microgrid, to meet domestic demands for electricity and space heating.

They describe the necessary electrical components, which include a photovoltaic array, a fossil fuel powered CHP generator (of which they consider several possible types), necessary circuit components and possible connection schemes, utility integration issues, and domestic load profiles.

For domestic load profiles, the authors created profiles, based on scenarios of a 3 person household, a variety of occupancy styles, and assumptions about demands for appliances, lighting and heating. Two figures for "typical" demands are included. Figure 5 depicts the electric power consumption by a "typical" household over two days. Figure 6 shows the average load profile of a single house, averaged over 100 winter days. The authors take this as profile to be an approximation of the load profiles of 100 houses on a single day. They note that the profile is relatively smooth, and "*approaching the standard domestic load profile quoted by the former UK Electricity Association.*" The authors note that the peaks from use of the 7kW electric shower are still fairly prominent, and aggregations larger than 100 would be needed for these peaks to *"'blend in' to obtain a smooth profile overall"*.

The article states that the predicted load profiles, when combined, agreed fairly well with UK statistical data, and that *"the creation of demand models corresponding to actual pattern using stochastic techniques should be a subject of further study."*

The article goes on to attempt to investigate size of components needed to achieve autonomy in a microgrid powered by photovoltaics and micro-CHP. The input data they use include: for PV arrays: south of England insolation values on a south-facing roof inclined at 40 degrees (for summer and winter); electrical demands from Electricity Association data; thermal demands obtained by another model (the Martin Model, developed at one of the author's institutions, which is also described in the article). Modelling appears to be done with time steps of five minutes.

The report found that autonomy could be achieved with the following: a photovoltaic array of "about 1.5kW$_p$" on every roof, a micro CHP unit in every other house (or fewer, if the micro-CHP is fuel cells), and electrical storage of about 2.7kWh per household.

The required size of energy storage could be reduced by about 1.4kWh by time-shifting appliances (washing machines, dishwashers and tumble driers) to times of available electricity from CHP generation peaks in winter, or generation from solar panels in summer. The use of thermal storage would allow further reduction in battery size, by about 1kWh.

An economic analysis found that the microgrid was not financially attractive with current prices, but they could become attractive in the event of a fall in the price of photovoltaic panels, or Government subsidies.

Figure 5 The typical electric load profile of a household over two days. Abu-Sharkh et al, 2006 [29]

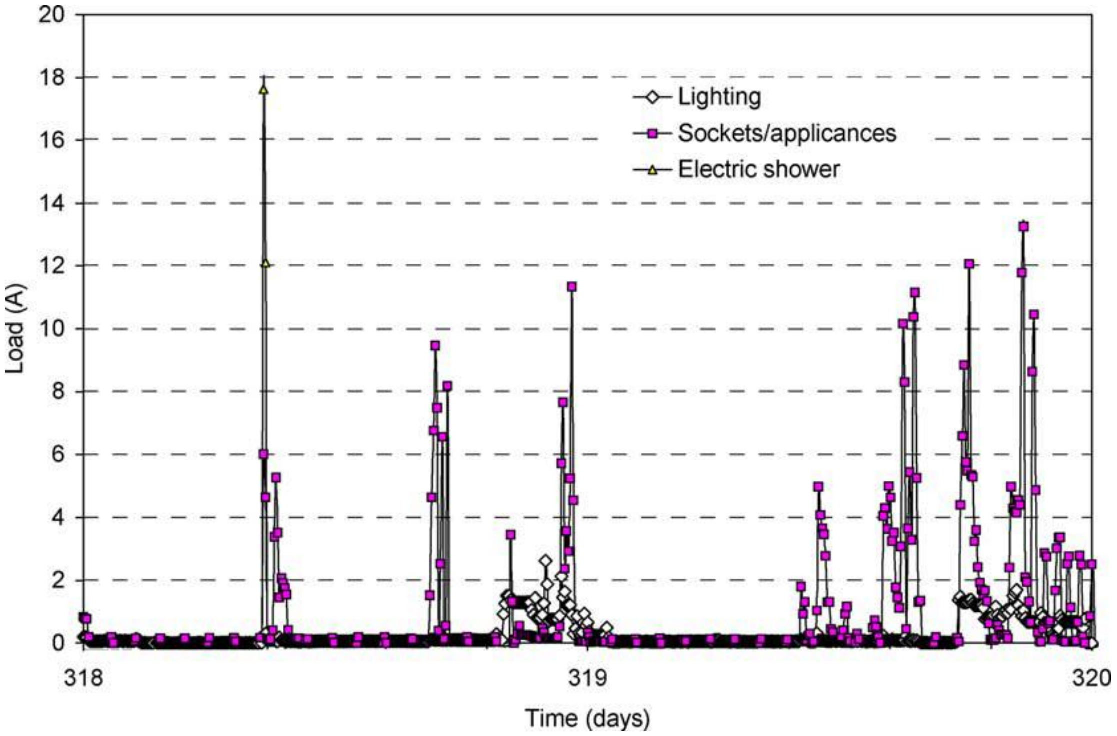
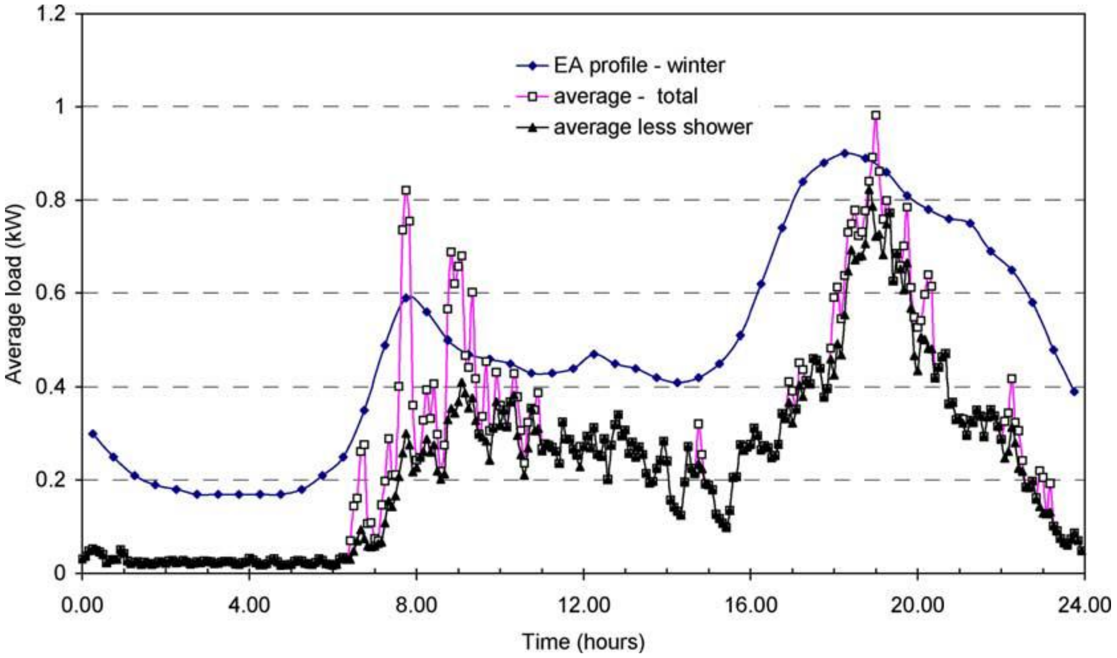


Figure 6 The domestic load profile averaged over 100 winter days, compared with the standard winter domestic profile produced by the Electricity Association. Abu-Sharkh et al, 2006 [29]



This was a relatively early study into balancing of a microgrid. While the results are not readily applicable to the current study, as the scenarios are very different, it is interesting to compare demand patterns for electricity, and to note the size of storage recommended. This is covered in Section 7.

3.3. Solar data

Solar data in Europe, and more recently other parts of the world, have been compiled by the Photovoltaic Geographical Information Systems (PVGIS) Project [33], which is part of the European Commission Joint Research Centre, Institute for Energy and Transport. It is a comprehensive collection of climate data, with associated user-friendly tools, available for free, for example [34], which allows monthly and daily solar data values to be interrogated for a chosen location, orientation and inclination. It is assumed that PVGIS data are reliable, and suitable for use in this study.

3.4. Studies on demand patterns: the Richardson model

Researchers at Loughborough University, Richardson et al, 2010, have developed a stochastic model to simulate domestic demand for electricity in the UK [35], which is available for free download as an Excel workbook [36]. Some excerpts from this model are displayed in Appendix 2.

Model outputs

The model creates a profile of domestic electrical demand, for a single household, at one minute intervals, over one day.

Model inputs

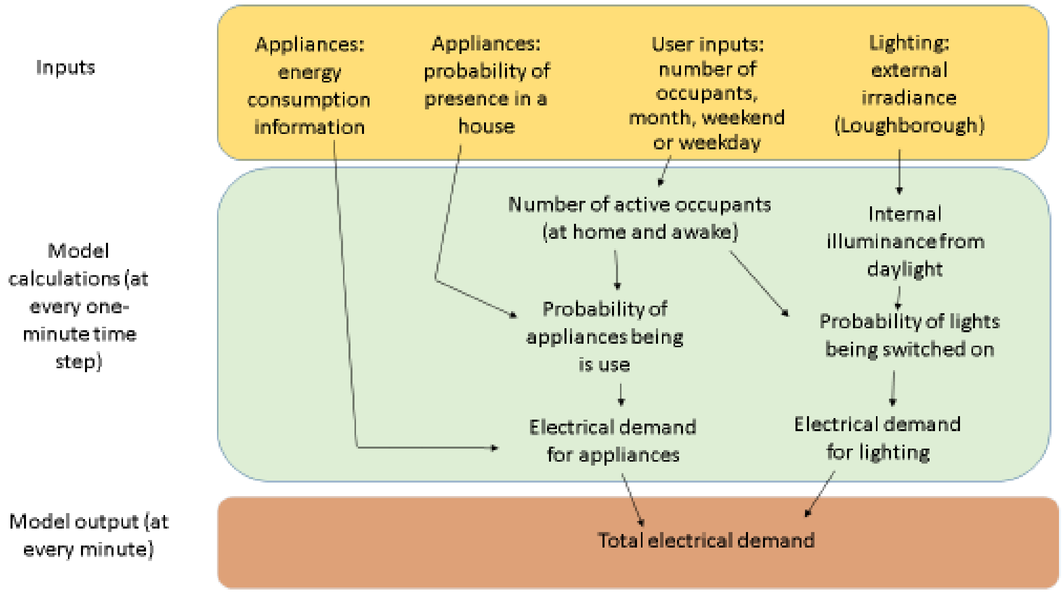
Users are required to input: month of the year, number of occupants in the household, and weekday or weekend. There are default settings of the probability of households owning various electrical appliances, which can be amended. External irradiance data for Loughborough is included, which could also be replaced by a different data set.

Construction of the model

A summary of the model is depicted in Figure 7.

.

Figure 7 Summary of the Richardson Model[35]: calculation of domestic electrical demands



Model calculations

The model stochastically estimates "active occupancy", that is, the number of people who are in a house, and awake, at every one-minute time step. This estimation is based on UK Time of Use Survey 2000 (TUS) [37], a comprehensive survey in which people in thousands of households were asked to complete diaries for one day, detailing what they were doing every ten minutes (when awake), and giving other supporting information.

The model then assigns the probability that various appliances are in use, at every minute, again, based on TUS data. A separate lighting model [38] is used to simulate demand for electric lighting.

Other considerations: sharing of appliances, correlations of use, temporal resolution

The authors state that the model takes account of the likelihood that some appliances will be shared by more than one occupant, and that the use of some appliances is correlated (the authors give the example that watching television and electric lighting would be likely to occur together on a winter evening).

Regarding choice of time-step, the authors believe it is important to have one-minute resolution of data, citing other research [39] which found thirty-minute demand data under-estimated imports and exports of electricity, compared to demand data at one-minute intervals, and that *"a considerable amount of detail is hidden regarding 'high frequency variations' of loads."*

Model validation

The paper describes how the model was validated by measured data of electrical demands in 22 houses (which were independent of data on which the model was built). There was good agreement between measured demand profiles and those predicted by the model, though the model may underestimate extremes of range. (The measured data found of the 22 houses, those with the very highest and lowest demands lay outside the demands predicted by the model.) It also found the model very closely modelled transitions in electrical demand from one minute to the next, of "medium" size (100-1000W), but underestimated "small" (10-100W) and "large" (over 1kW) changes.

Regarding time-coincident demand, three metrics were used to compare the model's synthetic data, with measured data from the 22 houses. They were:-

- **Maximum non-coincident demand**: that is, the sum of the maximum demands from each house.
- **Maximum diversified demand**. It is not likely that the maximum demands from all the houses occur at the same time. The "maximum diversified demand" is the maximum, time-coincident demand from all the houses together, which is likely to be much lower than the maximum non-coincident demand.
- **Diversity factor:** a ratio of the two metrics.

The authors report very good agreement between modelled and measured data, for all three above metrics, and conclude the model succeeds in realistically representing the time-coincidence of electrical demands.

Limitations of Richardson Model

1. There is no provision to input the "lifestyle" of occupants. For example, households in which everyone is in full time work during the day will have

different profiles from households where occupants are retired, unemployed, shift-workers, or adults caring for young children. The TUS data appear to cover all sections of society, and it is considered likely that the Richardson model gives a good "UK average" of such factors. However, a development of the model to include "lifestyle" inputs would be very valuable. This is an area of active research, for example Flett and Kelly (2016) predict occupancy based on several lifestyle categories [40]. However, they state their model is limited by the absence of large, comprehensive datasets, and they believe it is suitable for a collection of households, but does not model individual houses well. Clearly, further such developments in demand models will be valuable.

2. The model, as available, performs single runs of 24 hours. It requires modification for multiple runs, or longer time periods.

3. It is not possible to model "the same house" for example in summer and winter, because all runs are individual and stochastic. However, the model could be modified to input a pre-set appliance allocation, which would go some way towards modelling "the same house".

4. It is unfortunate that Richardson et al do not define at what age a person becomes an occupant. This is relevant when attempting to estimate demand profiles for families with young children, as it is not clear how many family members should be included in the "number of occupants" input. It is, however, noted that the TUS survey data [37], on which the Richardson model is based, consisted of questionnaires given to all persons aged eight and older. Thus, this author makes the assumption that for this model, "occupants" are all adults and children aged eight or older in a household.

5. The model's authors also cite areas for improvement: that the model underestimates transitions in electric demand which are both small and large (though is very close to measured data for medium sized transitions); that it underestimates demand at night, for example appliances running on timers, or people leaving lights on when asleep.

Assessment of the Richardson model

Despite the limitations described above, the Richardson model is considered robust, realistic, and suitable for use in this project.

3.5. Types of available storage

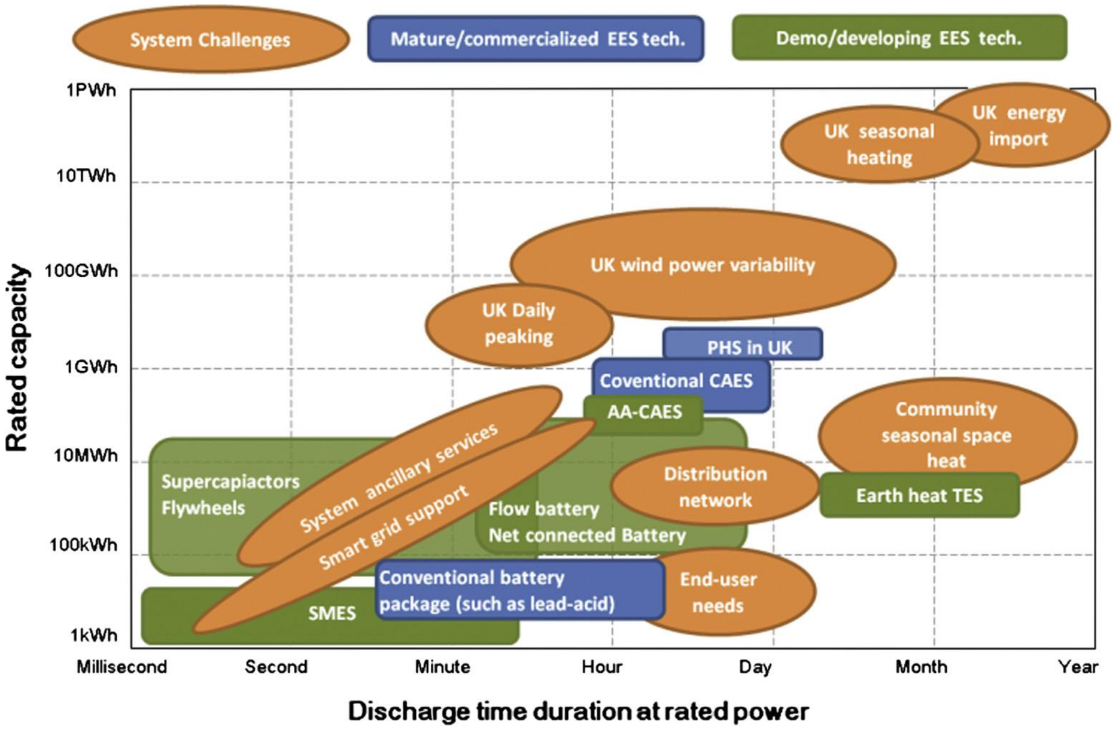
Storage systems have been discussed in detail by many authors, and so will only be briefly described here.

Thorough reviews of different types of electrical storage are made by Chen et al (2009) [41], Beaudin et al (2010) [42], and Luo et al (2015) [43]. Shorter but useful reviews included in Buchholz and Styczynski, 2014 [44], Teng et al, 2015 [26], and the Carbon Trust and Imperial College 2012 and 2016[11, 12].

Storage can be used on a wide range of time periods, from fractions of a second, through to seasonal storage, as depicted below in Figure 8.

This thesis discusses some of the options that are suitable for "peak shaving" in highly distributed systems, i.e. in the kW/kWh scale (suitable for a house) over a timescale of hours, which could allow renewable generation to be used later the same day or within a few days.

Figure 8 Electrical energy storage technologies, and system challenges, relevant to the UK energy system. Reproduced from Luo et al, 2015 [43]



Summaries of some storage system characteristics are reproduced in Table 1 - Table 4. Many storage types are not included (for example, pumped hydro storage, compressed air, capacitors and flywheels) as they operate at different scales of energy, power or time.

Table 1 Selected best case characteristics of the most commonly used batteries. Buchholz and Styczynski, 2014 [44]

Parameter	**Pb acid**	**NiCd**	**Li ion**	**NaS**	**ZEBRA**	**Redox flow**	**Zn-Br flow**
Energy density, kWh/litre	0.075	0.15	0.73	0.2	0.16	0.05	0.04
Efficiency per cycle, %	85	75	94	92	83	74	70
Lifetime, years	6	11	14	20	>20	18	7
Cycle durability, n	1,000	2,000	10,000	2,500	15,000	13,000	>2,000
Self-discharge, %/day	0.005	0.4	0.1	0.05	0.05	0.1	0.24
Depth of discharge, %	80	80	80	100	100	100	100
Maintenance, % CAPEX	1	1	0.8	0.8	0.8	1.5	1.5

Table 2 Comparison of technical characteristics from electrical energy storage systems. From Chen et al, 2009 [41] and Beaudin et al, 2010 [42]

Parameter	**Pb acid**	**NiCd**	**Li ion**	**NaS**	**ZEBRA**	**Redox flow (V)**	**Zn-Br**	**Metal air**
Suitable storage duration	Minutes -days	Minutes –days	Minutes-days	Seconds - hours	Seconds – hours	Hours-months	Hours-months	Hours-months
Maturity	Mature	Used	Commercialising	Commercialising	-	Developed	Developed	-

Table 3 Comparison of estimated costs of storage, per unit energy. From Chen et al, 2009 [41], Buchholz and Styczynski, 2014, [44], and Teng et al, 2015 [26]

Parameter	**Year**	**Pb acid**	**Ni-Cd**	**Li ion**	**NaS**	**ZEBRA**	**Redox flow (V)**	**Zn-Br**	**Zn / metal air**	**NiMH**
Chen et al, Capital cost, \$/kWh	2009	\$200-400	\$800-1500	\$600-2500	\$300-500	\$100-200	\$150 - 1000	\$150 - 1000	\$10-60	-
Buchholz Styczynski, CAPEX battery, €/kWh	2014	€120	€420	€330	€170	€270	€200	€100	-	-
Teng et al, 2015 capital cost, £/kWh	2015	£190 conventional / £420-840 “advanced”	-	~£480	£230	£320	£460	-	£120	£600-1100
Teng et al, Predicted change by 2020, capital cost £/kWh	*2020 (est.)*	No change	-	To halve, to £240	No change	No change	To fall, to £240	-	No change	No change

Buchholz and Styczynski [44] estimate the additional cost of a converter to be €100/kW for lead, Ni-Cd, Li, NaS and ZEBRA batteries, and €500-600/kW for redox and Zn-Br flow batteries.

Table 4 Comparison of estimated costs of storage <u>per unit power</u>. From Chen et al, 2009 [41], Buchholz and Styczynski, 2014 [44], and the Carbon Trust et al, 2016[12]

Estimate of capital cost	**Pb acid**	**Ni-Cd**	**Li ion**	**NaS**	**ZEBRA**	**Redox flow (V)**	**Zn-Br flow**	**Zn / metal air**	**Pum-ped heat**	**Liq. air**
Chen et al 2009 capital cost, $/kW	$300-600	$500-1500	$1200-4000	$1000-3000	$150-300	$600-1500	$700-2500	$100-250		
Carbon Trust capital cost: 2015 £/kW,	-	-	£556	£1961	-	£653	-	-	£523	£1693
Carbon Trust: 2030 capital cost, £/kW,	-	-	£584	£2571	-	£686	-	-	£549	£1779

Teng et al [26] note that there are several technologies offering relatively low-cost storage (<£300/kWh) but all have significant disadvantages. For highly distributed storage, in the kW / kWh range, the authors believe advanced lead acid batteries, and lithium ion batteries, to be the most suitable, and they note lithium batteries have higher rates of charge and discharge.

The performance of many types of batteries degrades with age. Lead-acid batteries, the most widely used at present in storage applications[43], are particularly prone to such degradation, which can be rapid, depending on conditions of use. Predicting performance and lifetime is not straightforward, because different ageing mechanisms can occur, depending on the type of charge-cycling environment, as described in numerous studies, for example [45-47].

It is interesting to note that the most recent Carbon Trust report on storage [12] does not even consider lead-acid batteries. However, some of the reports co-authors (Teng et al, [26], described above) include “advanced lead acid” batteries among competitive storage options for highly distributed storage.

It can be seen that for some technologies, most notably lithium ion, costs have fallen significantly since Chen et al ’s 2009 estimates, and are predicted to continue to fall as the technology matures.

It is speculated that the cost of lithium batteries may dramatically fall, if there is wide uptake of electric vehicles (EVs). EVs use a lithium battery to provide energy for motive power; partly-used batteries from vehicles may become available for a second life in less demanding stationary applications, as discussed by Chen et al, 2013 [48] and Cicconi et al, 2012 [49].

In summary, there are numerous storage technologies, at a range of states of technical and commercial maturity. Costs for all systems are significant: the cheapest operating in the "peak shaving" range, which may be suitable for domestic and community scale storage, include lead-acid and sodium sulphur, with vanadium redox and lithium ion systems having higher costs, which some authors expect to fall. Some systems have technical or practical issues which may limit their applicability in some situations, including limited cycle life (lead acid), the need to operate at high temperature (sodium sulphur), and large space requirements (redox flow batteries).

3.6. Carbon Trust and partners at Imperial College, London: investigations into the value of electrical storage in the UK

The Carbon Trust, and collaborators working at Imperial College, have done considerable research into the potential value of storage systems to the UK electrical grid.

The main body of work, in both Carbon Trust and Imperial College 2012 [11], and 2016 [12], is a whole system model of the UK electricity grid, designed by Professor Goran Strbac of Imperial College London. Aspects of this work are also published in journals, for example by co-authors Pudjianto et al, 2014 [50], and Teng et al, 2015 [26], and a summary [51] was presented at All-Energy conference on renewable energy, Glasgow, 2016 [52].

Scenarios include "no progression" ("*a world of low affordability and low sustainability"*) in which there is neither finance, nor new targets, to enable or drive investment in renewables, and "gone green" (*"a world of high sustainability and high affordability"*) in which there is a high penetration of renewable generation, driven by strong environmental policy measures, and there is ample available finance for investment at both a system and at a domestic level.

The work includes comparisons of the costs of various generation types, both conventional and renewable, and the measures that would be needed to maintain grid stability. Scenarios are modelled with and without various types of storage.

Both bulk and distributed storage systems are considered and compared. The more recent report has more detail on distributed storage options.

The recent report [12, 51] found that storage can provide significant savings, of over £2 billion per year in 2030, in a future low carbon UK electricity system ("gone green scenario"). However, in the absence of stricter carbon emissions targets ("no progression scenario"), storage adds little value. The report found cases where both bulk and distributed storage are advantageous, and surmise that storage of both types can be important in a future grid system.

The business case of distributed storage with solar PV was also investigated, looking at a scenario of individual houses, and an aggregation of 90 houses, with

- A 2kW PV rooftop installation,
- A lithium-ion batteries of the Tesla Powerwall type (2kW/7kWh) of different sizes: 0.6kW and 2kW
- Demand profiles, using measured demand data taken from Low Carbon London Projects [53], taken from different demand categories (taking into account income of occupants and household size)
- Synthetic solar data [53]
- Time step of one hour [50, 53] and a modelling period of one year [53]
- Maximum diversified peak load across household types of 1.72kW
- An annual mean energy use of 5761 kWh.

Results are presented in Table 5 below.

The greatest revenue was generated by the larger system on an aggregated basis. However, the smaller system, 0.6kW, was the only one which was financially viable, because the capital costs were much lower.

Table 5 Undiscounted costs and revenues of storage systems, in domestic and community settings, with 2kW solar PV generation. Carbon Trust and Imperial College, 2016

Type of storage system	Cost: Capital & installation	Cost: O&M, lifetime	Revenue, load shifting, lifetime
2kW/7kWh storage, stand alone	£2449	£235	£1032
2kW aggregated system	£2449	£235	£1,411
0.6kW aggregated system	£961	£92	£1,182

Further simulations were done, on the 0.6kW aggregated system, with storage offering additional services: primary frequency regulation and network support. In both cases, the additional services provided additional revenue streams, and further increased financial viability. Simulations were further done with varying Time of Use domestic electricity tariffs: this scenario found storage provided even greater revenue; approximately 50% greater than in the flat tariff scenario.

In summary, the study found long payback times, of over 20 years, for installing storage systems associated with a single house (2kW rooftop PV, and 0.6kW storage asset). However, aggregating multiple houses (90) gave better financial performance, particularly for smaller storage systems: "*Leveraging diverse demand profiles in a community significantly improves the revenue of the storage system. While providing the same demand shifting service as the stand alone case, the storage asset provides a better commercial case that pays back in fourteen years. Since aggregation improves the utilisation of the storage system and returns higher value per unit of installed capacity, the business case is thus better for the smaller asset (0.6kW) in the sizes of storage considered in this analysis.*" [12]

The Carbon Trust's Andrew Lever stated: "*It makes no sense to put a battery in our garage. It does make sense to have community-level storage.*" [51, 54]

Interestingly, the report's authors state that they believe this kind of battery use to be "socially sub-optimal", in that significant "behind the meter" use of storage will reduce the bills of consumers' who have storage, but, as they will pay less towards costs of the network, a large-scale rollout could result in higher charges for other consumers.

3.7. Other studies on storage for renewable energy systems

Storage is the subject of much research. A few examples are described below.

Del Granado et al (2014) [55] studied the implementation of domestic storage in a UK context, in a smart-grid context, with scenarios which include domestic wind and solar thermal generation, electrical storage in a battery (flooded deep cycle lead acid) and thermal storage in a hot water tank. The study uses wholesale spot prices of electricity and gas, and measured data for energy consumption, and weather, from three-bedroom, detached, low-energy homes in Milton Keynes Energy Park (1989-1991). The study found that the battery increased the value of the wind turbine, and vice versa, i.e. these two items complemented each other economically. Combinations of wind generation and a single battery (1.4kW) achieved up to 50% reduction in electricity costs. Greater numbers of batteries increase electricity savings, but with “diminishing returns”. The researchers believe their study *“provides a lower bound on the value [to the whole electricity system (grid)] of storage at a domestic level”*.

Ratnam et al (2016) [28] discuss installation of storage in conjunction with domestic PV in an Australian context. They found that the operation of domestic batteries would differ, depending on whether the aim is to minimise household electricity bills, or reduce peak currents and reverse power flows on distribution networks. In other words, mitigation of peak and reverse power flows, which benefit the distribution network, comes at a cost to the consumer, from reduced revenues. This is particularly the case when there are varying time-of-use tariffs. The authors here investigate the “central control” scenario, in a case study of 145 consumers in a distribution network, each with PV generation and a 10kWh battery. The study found that, with careful parameter selection, the central control system mitigated against peak power flows in the network, without “disproportionately penalising” customers for battery operation. The authors write future work will further consider “trade-offs” between storage use for grids and individual consumers.

Shang et al (2016) [56] describe a particle swarm optimisation algorithm to optimise battery sizing in a Singapore context; Lamadrid (2015) [57] describes an optimisation study of energy storage, aiming to better use renewable energy resources in a USA setting; Kaldellis et al (2010) [22] describe algorithms to optimise sizing of storage systems, to complement PV in a Greek island setting, and Kerdphol (2016) [58] describes a particle swarm optimisation of a battery energy storage system in Japan. Other authors describe storage systems on a distribution grid scale in Hawaii [59] and Taiwan [60]. Studies into storage in continental European context include: optimisations in a microgrid context by Nick et al (2015) [61], on a larger smart grid setting by Lucas and Chondrogiannis (2016) [62], and a technical-economic assessment of large scale storage is performed by Loisel (2012) [63].

Taylor et al (2013) [64] describe the importance storage, on different scales, can play in a future low-carbon grid, and also details some of the barriers to this happening in the UK. Barriers include not just cost, but regulatory arrangements within the electricity industry, and the lack of incentives for members of the public to install or wish for storage close to home. The report takes a "co-evolutionary pathways" approach to modelling future energy systems, and highlights the importance of policy decisions which take a long term view, to achieve the possibility of the best system outcome.

While not academic, a consultant's report, Delta Energy and Environment's 2016 paper [16] and conference presentation [15, 52] are interesting. They look at storage, in conjunction with domestic PV generation, in Europe, and found relatively long payback periods of around 16 years with scenarios presented, though they expect these to fall in the next few years as lithium ion batteries are expected to become cheaper. They note that the majority of installers of domestic PV systems in the UK do not even offer storage as an option, a situation they expect to change. They also discussed several examples of alternative electricity trading schemes, in the UK and Germany, where domestic generators and users of electricity can trade with peers, and with the grid, via a third party. Such systems offer the possibility of a small revenue stream to houses with storage or generation, and additional options for consumers wishing to purchase renewable energy. These papers shows there are alternative ways small-scale storage can be used, which, together with predicted falls in costs, may encourage its wider implementation.

3.8. Studies on domestic and community storage: previous RESE MSc theses

Dodds (2015) Feasibility study of small-scale battery systems for domestic application [13]

Dodds studied the feasibility of domestic generation, combined with batteries, in two locations: Aberdeen and San Francisco. He used half-hourly demand data, retrieved from University of Strathclyde's Merit tool [65], for UK and San Francisco demand profiles. Using HOMER, a tool developed in the USA to model performance of renewable energy systems and so facilitate their implementation [66], he modelled a three-bedroom domestic house, with solar and wind generation, in both locations. Climate data used was from NASA, available in the HOMER database. Dodds considered several battery types: lithium ion, flooded lead-acid and lead-acid gel batteries. Electricity prices were taken to be 15p/kWh, from a major UK electricity supplier for purchase from the grid, and Dodds assumed a much lower export price (4.85p/kWh) from the Energy Saving Trust. He made an assumption that there would be no feed-in-tariff. His calculations included whole system costs, including for the generation, as well as the storage components. Simulations were run, at one-hour intervals, for the system lifetime of 15 years, for both grid-connected, and stand-alone systems. He found several systems in which all electrical demands were met by generation and storage; however, these were accompanied by large excesses which were not used, and high costs. In many cases, if there was the possibility to interact with the grid, and buy and sell electricity, it made more financial sense to do so than to use storage. Dodds found significant differences between the battery systems he examined, in terms of throughput, variation of State of Charge, and cost. Dodds found that lead-acid batteries had lowest net present cost, but lithium ion batteries generated greater revenue due to higher quantities of throughput of electricity.

De Bartolo (2015) Strategies for harnessing and integrating renewables into electricity consumption and their application to ecovillages [67]

De Bartolo studied two very different eco-communities: Findhorn (in Scotland) and Tamera (in Portugal). She considered potential for generation, based on climatic data, and utilised actual demand data which are recorded as part of a larger project (the ORIGIN project[68]). Strategies she considered included incorporation of electrical storage: she studied several storage types, and their performance, in detail. De Bartolo used HOMER to model the systems, with one-hour resolution, over a whole year. She notes that, while HOMER is a comprehensive and much-used model, it does have limitations, including significant difficulties in modelling storage systems.

She concluded that increasing renewable capacity and storage systems increase the utilisation of renewable generation in these communities, though there are limits on the capacity of renewable energy systems, due to financial, practical and environmental constraints. The outputs from her simulations, findings about which systems would be "optimum", were very dependent on numerous equipment and financial parameters. She did note that lithium ion batteries showed *"promising opportunities in the future design of community energy schemes",* though were costly, and made further recommendations regarding system design and modelling.

Kelepouris (2015) Using Storage to Increase the Viability of Community Energy Schemes [21]

Kelepouris notes as background, that grid constraints limit expansion and full utilisation of renewables schemes. Using Dalavich, a remote village in Argyll, Scotland, as a case study, he considers potential community generation schemes (hydro-electric, wind and photovoltaic generation) and the potential for storage (flow batteries, lead acid, lithium ion, sodium sulphur, zinc-air and compressed air energy storage), to increase the viability of such schemes. Using a simulation tool he developed in Visual Basic, he modelled different sources potential sources of generation, together with demand, and storage options, using a one-hour time resolution, for one year. He performed financial analysis using the Feed-in-tariff payments available at the time.

Kelepouris found a massive quantity of electrical storage would be needed to achieve autonomy, or to avoid curtailment. He considered storage on such a scale would be impractical. His analysis led to the recommendation of vanadium flow batteries as the preferred storage type; and run-of-river hydro as the preferred generation type, and out of a choice of two possible microgrid configurations, the larger was more promising. The author is careful to note these results may not be applicable to other cases. He found that installation of storage could improve viability of community scheme, with benefits increasing with larger quantities of storage (comparing a 4MWh and a 16MWh storage arrangement, where the quantity of curtailed renewable energy generation over the year was between 600 and 700MWh, and total demand was around 300MWh).

His recommendations include a detailed financial feasibility study on the energy storage system, and generation scheme, to investigate long-term benefits and costs; and alternative approaches to reducing surpluses in energy, such as demand side management.

Gandarillas (2015) Feasibility of small scale energy storage technologies in rural areas [69]

Gandarillas studied the same Scottish village of Dalavich, to simulate a microgrid using run-of-river generation, and considered a number of both thermal and electrical storage types. He also developed a software, in Visual Basic, to complement HOMER, in recognition of some of the “gaps” in that tool. Simulations were done with hourly data. Gandarillas concluded that electrical storage was not financially viable, due to high capital costs. He investigated the possibility of future falls in battery costs improving viability, but in all scenarios, batteries systems remained uneconomic. However, Gandarillas found that thermal storage, in hot water tanks was financially viable.

Summary of findings from the above theses, relevant to this study:

- If electricity can be exported to the grid, in return for payment, it often does not make financial sense to install electric storage, due to current high capital costs. Electrical storage becomes more viable when there are grid constraints limiting exports, or high charges for importing electricity.

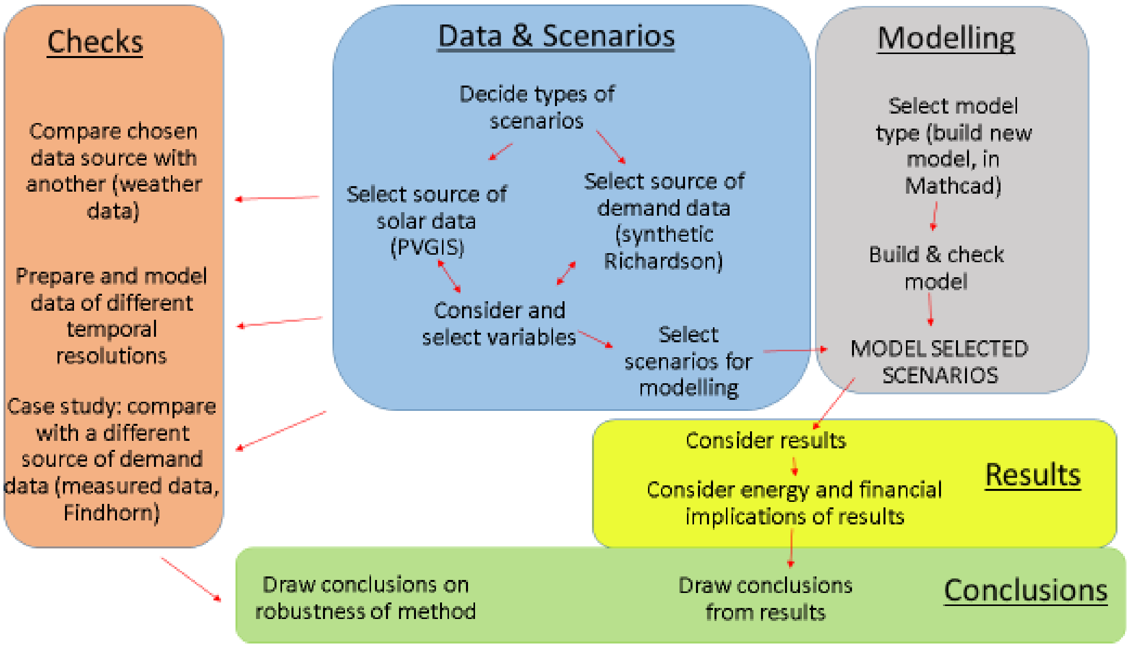
- Lithium batteries performed better than lead-acid, but were more costly. In some cases, vanadium flow batteries were the best performers.
- HOMER is a powerful tool for modelling renewable energy performance. However, it also has significant limitations, particularly regarding energy storage systems.
- All the above studies modelled at a resolution of half an hour or one hour, for a period of at least a year.
- It is not straightforward to compare results and conclusions, as scenarios and assumptions differed. Caution must be used in applying findings to any other situations.

4. Method and approach

4.1. Overview of Method section

Figure 9 summarises the method followed in this study. The component parts are discussed in turn.

Figure 9 Schematic of method used in this study



4.2. Selection of types of scenarios to use

It was decided to select scenarios in which all homes are grid-connected at all times. This assumption was made because it is the case for the vast majority of UK homes and businesses. Thus, it was not considered necessary for any of the scenarios to meet the criteria of being *microgrids*, i.e. to have control systems which enable them to function independently of the grid. Thus, all homes can purchase electricity from the grid during times of deficit in their own renewable generation, or supply from their own storage systems.

However, it is assumed that there are control systems which allow aggregation of a number of households, so that non-coincident demands have the potential to make better use of local generation from PV panels and storage systems.

It is also assumed there are constraints in the case of export of power to the grid. This thesis considers the context in the UK: UK Government policy, which previously offered generous financial incentives to install solar and other renewable generation and export to the grid, (via the Feed-in-Tariff, [14]) has changed in the last year, and payments have been significantly reduced. Furthermore, considering the difficulties for distribution networks that *uncontrolled* exports of renewable generation can cause (as discussed in section 3.1 of this thesis, and by [28, 30, 31]) a future scenario is used: *that there is no payment for the export of electricity*. (An exception to this is considered briefly, set out in Section 4.10.)

4.3. Selection of data to use for demand and generation profiles

The aim was to use input data which would be representative of many UK dwellings.

Generation

As stated in Section 2.2, rooftop solar photovoltaic generation was chosen as the renewable energy source, as this is considered the most realistic in a highly populated urban environment. It was decided to use PVGIS solar irradiation data, [33], as a reputable source.

For "daily data", average values of solar irradiation are provided for the selected month. The tool provides outputs of "global irradiance", "global diffuse irradiance" and "clear sky irradiance" (an example of which is appended in Appendix 1). These values are taken as proxies for "average", "cloudy" and "clear" conditions, respectively, for that month.

A limitation of this model is that it does not have an output of day-to-day weather. Thus, this study includes a brief comparison of PVGIS data, with a small sample of climate data stored in Strathclyde University's Merit programme, for the chosen location, Glasgow.

Demand

It was decided to use the Richardson model [35] to make high-resolution synthetic demand profiles which are representative of UK demand. These were the data source for urban and rural scenarios. An example of this model inputs and outputs is appended in Appendix 2.

Later, some real data from a rural community in Findhorn were used, discussed in Section 4.9.

4.4. Model selection and development

Selection of model type

Recent theses[13, 67, 69] have used HOMER [66], a powerful and widely-used modelling tool, developed to facilitate appropriate use of renewable generation. Some researchers [21, 69] wrote their own programmes (in these cases, in Visual Basic).

In considering which approach to use, previous researchers' comments [67, 69] (as discussed in Section 3.8) regarding the limitations of HOMER, in particular to accurately model some storage systems, were taken into account.

It was also noted that all previous theses cited above, (and also other models, such as [12, 29] described in Sections 3.2 and 3.6) used a temporal resolution of half an hour or an hour.

This study aimed to use data of one-minute resolution. The importance of this resolution is described by Richardson et al [35] and in Section 3.4 of this thesis. It appeared that HOMER can accept data, but not model, at this resolution. Thus it was decided to construct a bespoke model. The author selected Mathcad 15 as the programme.

Limitations of selected approach to modelling

HOMER and other programmes, such as MERIT, are suitable for full annual simulations and can model periods of several years(for example, [13]).

The approach selected here would not be able to do that. Using higher resolution data, it aimed to model a selection of several different scenarios, for a single day.

Different "days" could be used, for example summer and winter, clear and cloudy, but extrapolations to estimate annual totals must be viewed with caution. However, it was hoped that these "snapshots" of performance, even though limited in number by the constraints of the project, would nevertheless be able to provide a useful comparison of different scenarios, and shed some light on the questions this thesis aims to investigate.

Model development

The calculations were done in several stages, using different Mathcad sheets and some Excel.

The algorithms were initially trialled with very small artificial data sets, before moving to generation and demand datasets covering 24 hours.

The methods are summarised in flow charts below. Figure 10 summarises the whole process.

Figure 11 and Figure 12 give greater detail in the steps to obtain electrical generation and demand data, and Figure 13 summarises the calculation where there is storage. Appendix 3 summarises the investigation into the effect of inclination of roof, on quantity of generation. Appendices 4-8 give examples of the Mathcad calculation sheets which were developed for the above calculations.

Figure 10 Overview of calculation

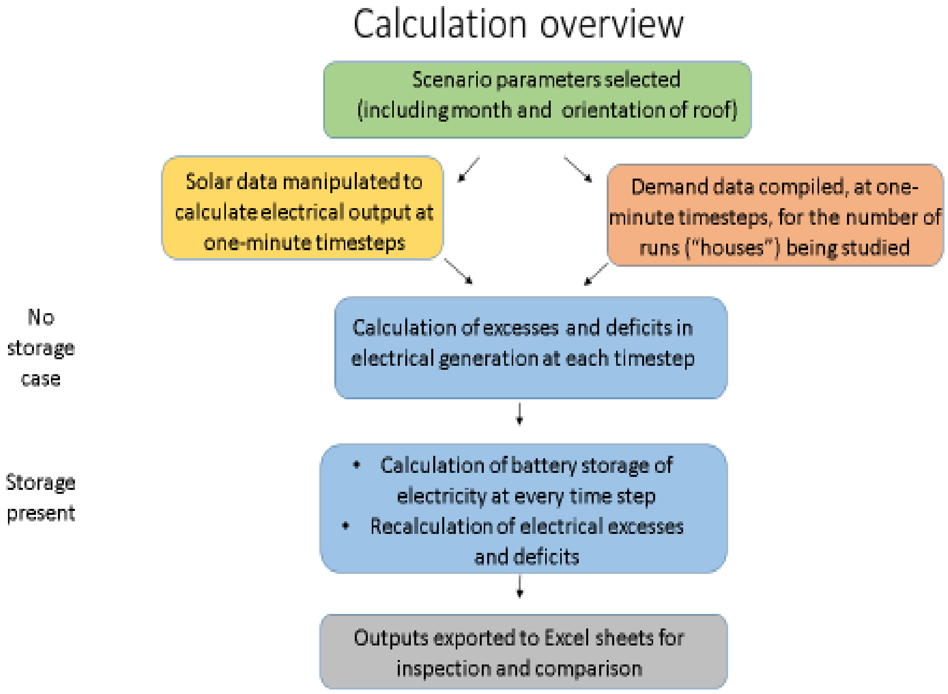


Figure 11 Converting solar data to electrical data

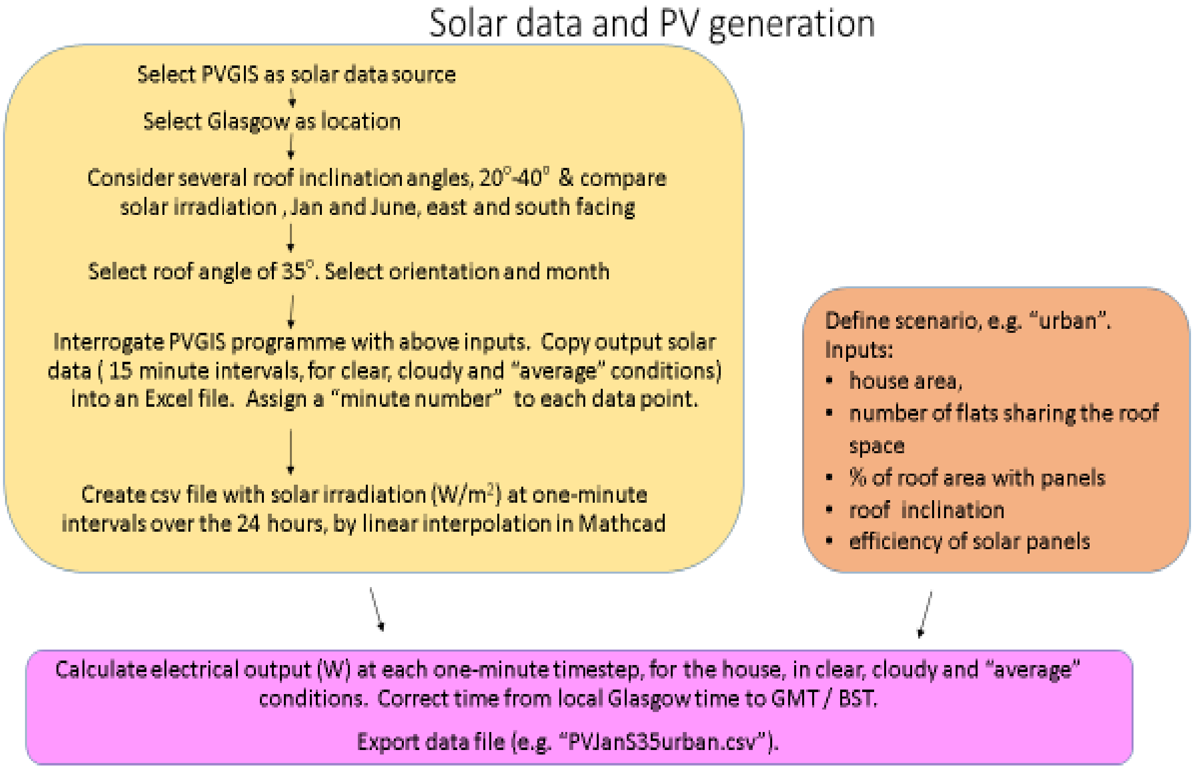


Figure 12   Summary of calculation to obtaining electrical demand data

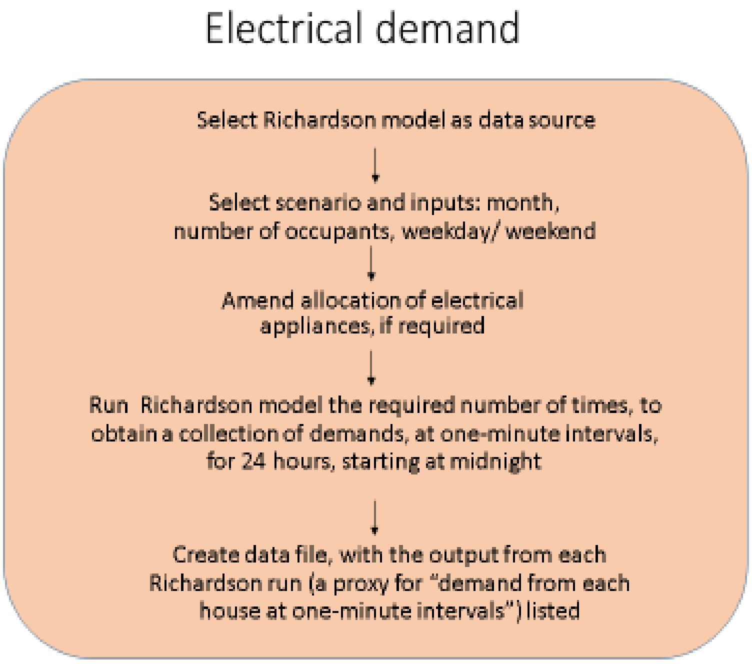
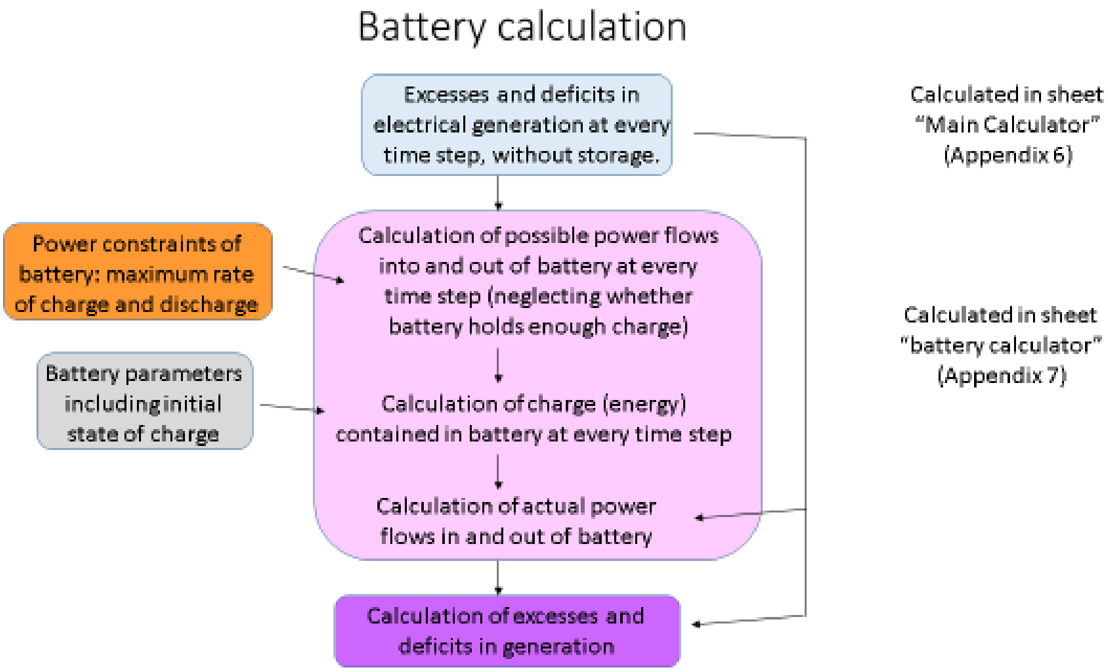


Figure 13   Summary of calculation of excesses and deficits, in the case where there is storage



Model testing and validation

The calculations were checked in a number of ways.

Initially, a small sample, of six demand runs was modelled. (The runs were generated by the Richardson model, with 2-person occupancy, mid-week, January, and default appliance allocations.)

Electrical generation was calculated for clear, cloudy and average conditions, initially in January only. The initial scenario selected was of an urban tenement flat, with a south-facing half of roof completely covered in PV panels. To trial the model, excesses and deficits were only calculated for clear sky conditions, as these solar insolation values were closer to "mid-range" annually.

Input battery parameters were chosen to test the model, rather than follow specific battery types.

For the initial six runs, selected to trial the model, the following checks were made in every worksheet (examples of which are included in Appendices 4-8).

- Downloaded data sets were inspected to ensure they had the correct number of time steps, and the data values were consistent with original data sets.
- Calculated parameters were examined graphically, and areas of interest interrogated, to examine consistency with one another, and with expected patterns.
- All data and calculated parameters were examined to ensure there were no negative values, as any such values would indicate errors in calculations.

Separate manual calculations were performed for several parameters: day total electrical generation by PV panels; the time (in the morning) by which the batteries' state of charge has reduced to zero, and the state of charge of batteries at minute numbers 300, 500 and 700. The checks are described in greater detail in Appendix 11.

In all cases, the model (after corrections) and manual calculations agreed. It was concluded that the model was validated and ready for use.

Automation of obtaining demand profiles

The Richardson model [35] allows simple calculation of electrical demand, for one single household, for one day. (An example is displayed in Appendix 2.)

Small numbers of runs were obtained by manually repeating the model. However, later, is was desired to study groups of 100 runs.

To do this, the downloaded Richardson calculation sheet [35] was modified, by writing an extra macro. This new macro instructed the Richardson calculation sheet to run multiple times (to a number set in a new input field) and put the output data – a series of demand profiles for all the runs – on a new sheet.

The new macro was tested thoroughly before use. Details are set out in Appendix 11.

4.5. Variables

A large number of variables were an essential part of the calculations. Below follows a discussion regarding which values were chosen, and which variables had fixed or several different values.

Variables associated with generation of electricity

Location

Glasgow was selected, being the location of study and residence of the author. Its large population makes Glasgow representative of significant electrical demand.

Time of year

Clearly the solar resource varies during the year. Two months were chosen: January and June, to represent winter and summer, giving upper and lower bounds to generation.

Weather

PVGIS data are for "global irradiance", "global diffuse irradiance" and "global clear sky irradiance", which are taken to describe irradiation on "average", "cloudy" and "clear" days. These were all modelled separately.

Efficiency of panels

While there are different types of panels available, a conservative value of 12%, including inverter losses, was taken for all cases.

Types of dwelling

The author's flat was initially used, being not untypical of an urban dwelling in Glasgow. It is a 1930s built, three-bedroom, three-storey tenement flat, shown below. This was used in "Ballindalloch" scenario (named after the author's street), and is shown in Figure 14.

Figure 14 Photo of type of housing for urban scenario "Ballindalloch"

A second type of urban dwelling, a late nineteenth century tenement flat (in this case, with one or two bedrooms), very typical of housing in Glasgow, was also considered, in "Onslow" scenario, shown in Figure 15. Rural housing was also modelled. Clearly there are many possibilities of house design and size; here a simple single scenario was taken.

Figure 15 Photo of typical Glasgow tenement housing, for "Onslow" scenario

There are many variables associated with the type of dwelling, listed below.

Area of house /flat

For urban Ballindalloch and Onslow scenarios, areas were based on actual measurements of the floor area of the flats (including portion of shared stairwell): 11m by 9m, and 12m by 8m.

For the rural scenario, a simple assumption was made that the area was the same as in the Ballindalloch scenario.

Number of households sharing the roof space

As can be seen in Figure 14, in the Ballindalloch scenario, there are three households sharing the same roof space (and thus any solar PV generation), and in the Onslow scenario (Figure 15) there are four.

For the rural scenario, it was assumed that the dwellings are houses, with only one household under the roof.

Angle of inclination of roof

Several measurements were made of roof gable ends in Glasgow. They were all around 30^o-35^o.

A sensitivity analysis was conducted to investigate the effect of roof angle, looking at January and June, for south and west facing planes, of angles 20^o-40^o. (This was done in Excel, and assumed solar irradiance was constant throughout each 15-minute period for which there was a data value.) The results are described in Section 5.1, and displayed in full in Appendix 3.

Guidance on roof construction was also referred to, from UK building standard-setting body NHBC [70]. Current standards state minimum permissible roof pitch angles as: 35 degrees for "plain (double-lap)" tiles; 30 degrees for "concrete (single-lap interlocking)" tiles *("unless evidence is provided as to suitable performance")* and 20 degrees for "slates (double-lap)".

Proportion of roof area available for PV panels

A best-case scenario was used here, in which the more southern facing portion of the roof would be entirely covered in panels: i.e. the proportion of 50% was used.

The same assumption was made for the rural scenario. Here this is considered to be optimistic, as in some cases complex roof structures will make fixing of PV panels impractical.

Orientation of roofs

It was assumed for all urban scenarios, that all streets will have the same orientation. This is often, though not always, the case in many urban streets. Some modelling was done investigating roofs orientated east, south-east, south, south-west, and west; some investigations chose a single orientation (south).

For the rural modelling, it was assumed that houses will have a variety of aspects. Equal numbers, therefore, were assigned the five directions stated above.

Variables associated with demand

Time of year

The same time of year were chosen as stated above, (January and June), to simulate winter and summer.

Weather

No input was made, as Richardson's model has no provision for such entries. Clearly, weather may affect heating and lighting demands, and possibly appliance use.

Location

There is no provision to alter the model because of location. While the model is considered to be representative of UK demands, as it is set in Loughborough, in the English Midlands, not Glasgow, there are likely to be some differences in lighting and heating demands. Glasgow may have a longer heating season, and does experience greater variation in length of natural daylight around the solstices.

Weekday or weekend

All modelled cases were for "weekday" demand patterns. This was done because there are more weekdays than weekends, and because this study aims to study temporal non-coincidence of generation and demand. Clearly, however, any annual estimations would need to include weekend patterns of demand.

Numbers of occupants

Initial modelling looked at two-occupant households.

An inspection was done looking at the effects of different occupant numbers (from one to five) on electrical demand.

High resolution census data, on a street level, was not readily available, so a scenario-based approach was used, in which there was a mixture of occupant numbers. Scenarios were based on the author's knowledge of current and previous neighbours in both "Ballindalloch" and "Onslow" type accommodation.

Rural housing patterns are expected to be very varied, and a single scenario was constructed here.

Occupant lifestyle

This is crucially important variable which is not entered, as discussed in Limitations of Richardson Model, in section 3.4. Clearly whether someone is at work during the day, at night, or not at all, will greatly affect patterns of demand. Some other studies, such as [50] used by [12], [29] and [40] have used different demand patterns, but at a lower temporal resolution.

Appliance allocation

The Richardson model [35, 36] sets the probability of appliances being present in a house, according to a number of data sources, including the UK Government statistics [71].

Demand patterns were compared with Richardson's default allocation (all 2-person households), and varying scenarios in which electricity was or was not used for space and water heating.

Scenarios were then devised for urban and rural simulations, which are described in section 4.6.

Variables associated with storage

Type of storage device

Some studies, for example [28, 50] do not specify a battery system, but input parameters into a model. Many studies recommend, or model, either lead acid, or lithium ion, or both [12, 13, 26, 55, 67]. Having considered the attributes of various storage devices, in Section 3.5, it was decided to consider two types of storage: lithium ion and lead acid. These are both commercially available in the UK, and suitable for domestic use.

For communal settings, other types of storage, such as sodium sulphur, or redox flow batteries, may be attractive. These were not investigated but could be a subject of further investigation.

Battery characteristics used in the modelling were based on the actual batteries described below.

Lithium ion:

Tesla Powerwall [72] and another similar battery by LG Chem [73], according to a UK distributor [74].

Specifications are detailed in Appendix 12-13.

Lead acid

A flooded deep cycle model is selected, Rolls Surrette, model 6 CS 17 P [75]. This is described as being robust, relatively tolerant of deep cycles of discharge, and suitable for renewable energy applications [74].

The specification is listed in Appendix 14.

(This model is similar to the Trojan batteries which Dodds [13] selected for study.)

Numbers of batteries

Scenarios were run with two or three different numbers of batteries, selected to be appropriate for reducing deficits in electrical demand.

Capacity (kWh), Charge and Discharge rates (kW), Efficiency, and Maximum and Minimum State of Charge

These variables were based on manufacturers' data, and the number of batteries selected. For each type of battery, a single value of capacity, and a single maximum charge / discharge rate was used, assuming slightly worse performance than that stated by the manufactures, to allow for a little degradation in use. This matter is described in more detail in section 4.6.

Maximum and minimum state of charge: a single pair of values was chosen for the lithium batteries, and another for the lead acid.

Initial state of charge / quantity of charge held

This was approached in several ways.

1) Assuming a constant quantity of charge (1.6kWh for the lithium batteries) – urban scenario
2) Assuming a constant state of charge (0.25, for the lead acid batteries) – urban scenario
3) Based on the mean / median State of Charge at the end of a similar run ("previous day") assuming same month, and clear, cloudy or average

conditions. This was done for rural scenarios, and some later urban investigations.

Variables associated with the modelling

Time step

A single time step of one minute was used for all synthetic data. Solar data, which is given at 15-minute intervals, were linearly interpolated to one minute.

A later part of this study briefly looked at the effect of smoothing these data to 5 minute and one-hourly resolutions, so that they could be compared with some real measured case-study data, and other studies

Number of runs ("houses")

The main studies used 100 runs, as Abu Sharkh et al [29] and Carbon Trust and Imperial College [12] used aggregations of 100 and 90 respectively, considering this number sufficient for an aggregation effect.

Some later studies considered six runs and 600. Six is the number of flats in a "close" in the Ballindalloch scenario (a shared stairwell of tenement flats) which have a common ownership of the roof). 600 was selected to investigate larger aggregations.

Numbers of runs in the case study (Findhorn data) were based on readily available data.

4.6. Selection of scenarios to model

Generation

As discussed above, the generation scenarios modelled were:-

- Urban Ballindalloch: using parameters for Ballindalloch scenario (99m^2 roof area, shared between three households. Streets in a single orientation)
- Rural scenario: using same roof area as Ballindalloch, but entirely at the disposal of a single household. Houses of mixed orientations

Demand

Household occupants

Scenarios were devised regarding household size.

For the urban scenarios, census data on a street level were not readily available, so scenarios were created based on local knowledge. For the rural scenario, clearly, patterns of household type will vary greatly from area to area. A simple scenario, assuming a mixture of household type, was used here. The scenarios are summarised in Table 6.

Table 6 Summary of scenarios: household size

No. of occupants in household	**% of households**		
	Urban		**Rural**
	Ballindalloch	**Onslow**	
1	6	30	30
2	48	54	20
3	30	12	20
4	8	4	20
5	8	0	10

Appliance ownership

Urban scenarios

It was assumed that all properties were on mains gas networks, and used gas for space and water heating. For other appliance ownership, Richardson's default allocations, displayed in Appendix 2, were used.

Rural scenarios

It was assumed these properties were not on mains gas networks, and so the proportion using electrical heating would be higher than the national average, though there would be significant numbers of housing with other fuel sources, such as solid fuel, oil-fired heating, or bottled gas. Higher proportion of electric cookers were assumed than the national average, and lower tumble drying (assuming there would be more space to hang washing outside).

This scenario-based approach was not based on data. The scenarios are summarised in Table 7.

Table 7 Summary of appliance ownership assumptions, rural and urban scenarios

Appliance ownership	**Richardson default**	**Urban scenario**	**Rural 1**	**Rural 2 (recalculated Jan only)**
Electric space heating	2.6%	0%	50%	50%
Electric storage heating	2.8%	0%	20%	0%
Electric water heating "DESWH"	17%	0%	50%	50%
Electric water heating "E-inst"	1%	0%	10%	10%
Electric shower	67.0%	67.0%	67.0%	67.0%
Electric cooking –hob	46.3%	46.3%	80%	80%
Electric cooking - oven	61.6%	61.6%	80%	80%
Tumble dryer	41.6%	41.6%	20%	20%
Washer dryer	15.3%	15.3%	15.3%	15.3%

Storage

Lithium batteries

Manufacturers and suppliers state a 7kW model is available, able to deliver 6.4kWh of energy, with a total depth of discharge of 100%, and a power output of 3 / 3.3kW of power output, and an efficiency of 90% [72, 73]. More details are shown in Appendix 12 and 13.

The scenarios here assume slightly lower performance than that stated for a new battery, as shown in Table 8 and Table 9.

An efficiency value of 70% was selected. Efficiency is not clearly stated by the manufacturer. Thus the value chosen is somewhat lower than published literature would suggest (e.g. 85%, [44] shown in Table 2, discussed in section 3.5), to allow for greater energy losses at high power outputs / some degradation in service.

Self-discharge, suggested around 1-2% per month for lead acid batteries [74], was neglected in the modelling.

Lead acid

Modelling these batteries is more complex: battery capacity (the energy the battery can deliver) is a function of power output. Furthermore, the lifetime of the battery depends strongly on its conditions of use.

The battery selected has a nominal capacity of 546Ah at 6V, at the 20 hour discharge rate [75]. The battery is capable of delivering much higher output power, but will do so for a much reduced capacity (kWh), as shown in Appendix 14.

There are several approaches to dealing with this phenomenon. Del Granado et al [55], for example, used high and low power output characteristics, as upper and lower bounds of behaviour. De Bartolo [67] discusses how HOMER does not adequately model such "kinetic energy" behaviour.

For this study, a fairly crude approximation was used. A single value was assumed for capacity and for power. The values chosen correspond to the 5-hour discharge rate, of 366Ah at 6V.

Maximum charge was set at 80%, based on the "bulk charge" described in the Rolls battery manual [76], being normally around this level . Special charging arrangements are needed to completely fill the battery ("absorption charge"). It was assumed in renewable generation situations these conditions cannot be expected.

Minimum charge 20% (80% depth of discharge) was selected, as a compromise between maximising the use of the battery, while not unacceptably shortening its lifetime [75, 76].

An efficiency value of 70% was selected. Efficiency is not clearly stated by the manufacturer. Thus the value chosen is somewhat lower than published literature would suggest (e.g. 85%, [44] shown in Table 2, discussed in section 3.5), to allow for greater energy losses at high power outputs / some degradation in service.

Self-discharge, suggested around 1-2% per month for lead acid batteries [74], was neglected in the modelling.

Table 8 Characteristics of the batteries used in modelling

Characteristics	Lithium ion battery	Lead acid battery
General properties		
Efficiency	85%	70%
Minimum state of charge	5%	20%
Maximum state of charge	95%	80%
Self-discharge	0%	0%
Single battery		
Capacity (gross)	6.4 kWh	0.366 kWh
Max charge rate	3 kW	0.439 kW
Max discharge rate	3 kW	0.439 kW
Calculated available "net capacity"	5.8 kWh	1.318 kWh
Numbers of batteries used in scenarios	1 and 0.5. For some scenarios also 0.25	1, 2 and 4

Table 9 Characteristics of battery types and numbers used in modelling

	Lithium batteries			Lead acid batteries		
Number of batteries	0.25	0.5	1	1	2	4
Gross capacity, kWh	1.6	3.2	6.4	2.196	4.392	8.784
Net capacity, kWh	1.45	2.9	5.8	1.318	2.636	5.270
Max charge / discharge rate, kW	0.75	1.5	3	0.439	0.879	1.757

Modelling of selected scenarios

A large number of scenarios were run. The main variety of scenarios is summarised in Table 10.

.

Table 10 Summary of scenarios modelled

	Urban	Rural
Generation & demand profiles	"Ballindalloch"	"Rural 1" (Jan & June) & "Rural 2" (Jan only)
Orientations	Separately: E, SE, S, SW, W	Combined orientations
Numbers of runs	1 and 100	1 and 100
	6 & 600 south facing only	
Weather	Clear, cloudy and average	
Season	January and June	
storage	None, 1,2 & 4 lead batteries, half and one whole lithium battery	As for urban, with additionally one quarter lithium battery.

Urban results are presented in Section 6.2 and rural in 6.3

Initial assumptions that a low quantity of charge was in the batteries at the beginning of the runs (1.6kWh for lithium/ 0.25SOC for lead). Some runs were repeated with amended initial state of charge to simulate different weather conditions, with results presented in section 6.4. Further modelling was done, south-facing only, with different numbers of runs: six and 600. Results are presented in Section 6.6.

4.7. Comparison of PVGIS data with measured climate data

As a check on the applicability of the PVGIS solar data used in this study, a comparison was done with an alternative source of solar data: real measured weather data, for one year, (1972). The results are discussed in Section 5.3.

4.8. Comparison of different temporal resolutions

A brief comparison was made of the effect of different temporal resolutions. 100 runs, urban Ballindalloch scenario, June only, were examined: in the original one-minute resolution; and smoothed to five-minute and one-hour temporal resolution. Five-minute resolution was selected because this is the resolution of the case study data, described in Section 4.9. One-hour resolution was also examined, as this is the resolution used by numerous other studies. Demand profiles were compared, as were excesses and deficits in electrical generation. Results are in Sections 5.6 (demand profiles) and 6.7 (excesses and deficits in generation).

4.9. Case study: comparison with measured data from Findhorn

A body of electrical demand data in the Scottish village of Findhorn are available, as part of the ORIGIN project [68]. Detailed data are available, with numerous datasets for most properties.

Electrical demand data for domestic properties in Findhorn were interrogated, for one winter day and one summer day. It is believed that the data selected represent a single total electrical demand for each house. However, some caution must be used in examining these results. It was usually necessary to add several datasets to arrive at a house total: a more detailed study of the data would be needed to ensure these totals did not have any omissions or double-counting of any components of electrical demand. Furthermore, some datasets were missing a few demand data points. Nevertheless, it is believed this brief study allows a useful comparison with the synthetic demand data used elsewhere in this study.

Residential properties were selected according to there being readily accessible datasets on the chosen dates. Datasets missing more than one hour of data, or having different temporal resolution, were excluded. This resulted in 16 different properties for winter, and 31 for summer, being examined. Further details about these data are included in Appendix 21.

The datasets used were at five-minute temporal resolution. For comparison, synthetic data, of the same number of runs as the Findhorn data, were prepared. The synthetic data were selected from the 100 runs for the rural scenario, as Findhorn is a village. "Rural 2" (no storage heating) scenario in winter were used, because the Findhorn electrical demand data used had no storage heating. The synthetic data were selected with the same ratio of household occupancy as the bulk rural dataset. It is not known how similar or different this occupancy number is to the Findhorn properties. The synthetic datasets were "smoothed" to five-minute temporal resolution (from one-minute) to allow a better comparison of measured and synthetic data.

Demand profiles were compared. Both synthetic and measured data were run through the calculator used in this study. It was assumed that PV generation was the same as in Glasgow. Excesses and deficits in generation, with varying storage (lithium battery only) were evaluated. Results are displayed in Section 5.7 (comparison of demand profiles) and 6.8 (comparison of excesses and deficits in generation).

4.10. Potential savings storage and aggregation could bring

Savings in day total deficits in generation, for January and June

The effect of aggregation (of 6, 100 and 600 runs) and / or installing storage (both lead acid and lithium batteries, different quantities) on day total deficits for January and June were quantified. In all cases, it was assumed weather was "average" and the preceding day was also "average".

Urban Ballindalloch scenario: south facing, for aggregations of 6, 100 and 600, and lead and lithium batteries.

Rural 1 scenario: combined orientations, aggregations of 100, lithium batteries.

Results are shown in Section 6.9

Estimate of potential annual savings, kWh purchased electricity, and revenue

As described above, in the section: Limitations of selected approach to modelling, annual extrapolations must be viewed with caution. However, it was decided to attempt such calculations.

Flat-rate tariffs

From the January and June day totals in deficits, estimations were made of potential annual savings, assuming half the year is "January" and half the year is "June". Savings were evaluated in kWh purchased from the grid, and thus the potential revenue savings, based on two tariff scenarios: a current one, of 15p/kWh, and a future scenario, of 30p/kWh, for both urban and rural scenarios.

Variable tariffs

The financial calculations were then repeated with a scenario of time-of-use (TOU) variable electricity prices, detailed in Table 11. Scenario 1 is the same as used by the Carbon Trust and Imperial College in their study of storage in the UK [12, 53], scenario 2 is the author's chosen modification of this scenario.

Table 11 Scenarios of Time of Use electricity tariffs

Time of day	Tariff, pence/kWh	
	Scenario 1	Scenario 2
00:00-07:00	8	8
07:01-18:00	15	15
18:01-20:00	30	100
20:01-24:00	15	15

Variable tariffs with sale at peak times

A further air of scenarios were investigated: that it would be possible to sell electricity to the grid, during the evening peak only. These scenarios are shown in Table 12.

Table 12 Scenarios of Time of Use electricity tariffs, for purchase and sale

Time of day	Tariff, pence/kWh			
	Scenario 1		Scenario 2	
	Purchase price, pence /kWh	Sale price, pence/kWh	Purchase price, pence/kWh	Sale price, pence/kWh
00:00-07:00	8	0	8	0
07:01-18:00	15	0	15	0
18:01-20:00	30	25	100	80
20:01-24:00	15	0	15	0

4.11. Estimate of costs of installation of storage and aggregation.

Information on potential costs of different storage systems was gathered from manufactures and installers, and from published literature. The findings are summarised in Section 6.10.

Evaluating the costs of aggregation was beyond the scope of this project. However, information about some of the main types of equipment which would be needed for individual and aggregated systems, and size of potential projects, is included in Section 6.11.

4.12. Estimate of financial viability of storage and aggregation

Comparisons were made between:

- estimated annual revenue that various combinations of storage and / or aggregation would bring to a system which has PV generation, with
- various estimates of costs of battery systems

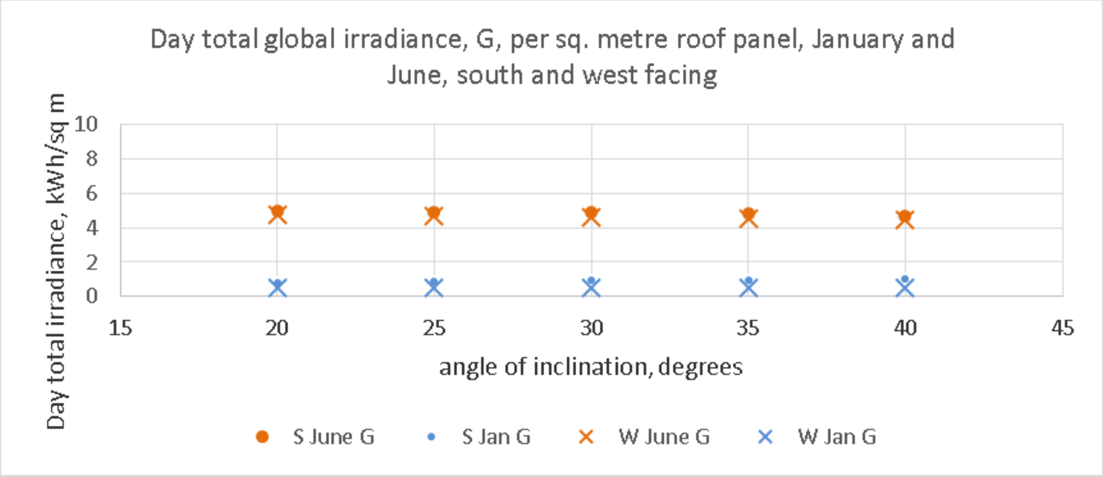
The results are presented in section 6.12.

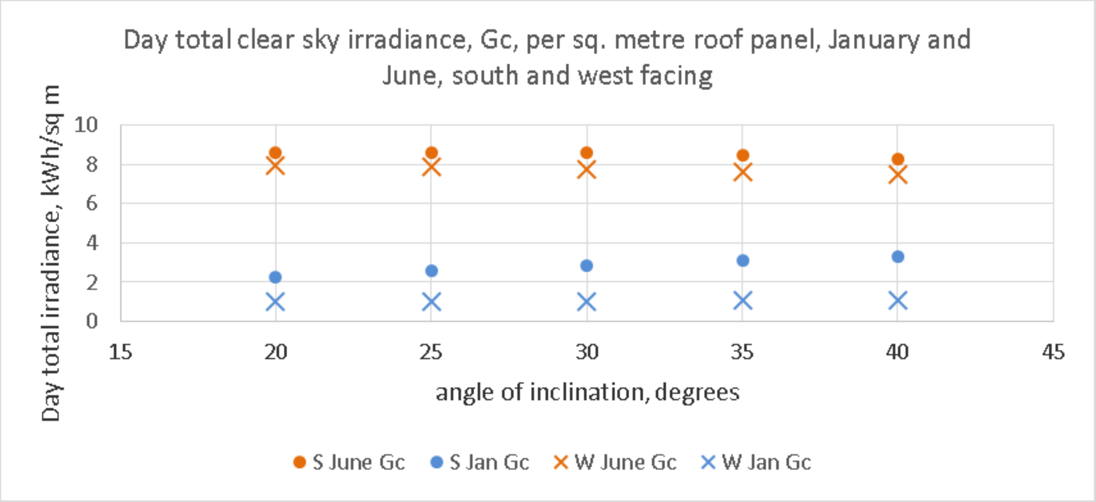
5. Preliminary results: investigations into system components

5.1. Angle of roof investigation

Day totals for solar energy, per square metre of inclined surface (e.g. solar panel on a roof), were calculated. A selection of results are shown in Figure 16. Full results are in Appendix 3.

Figure 16 Day total global irradiance per square metre of inclined surface ("roof area"), as a function of angle of inclination of roof

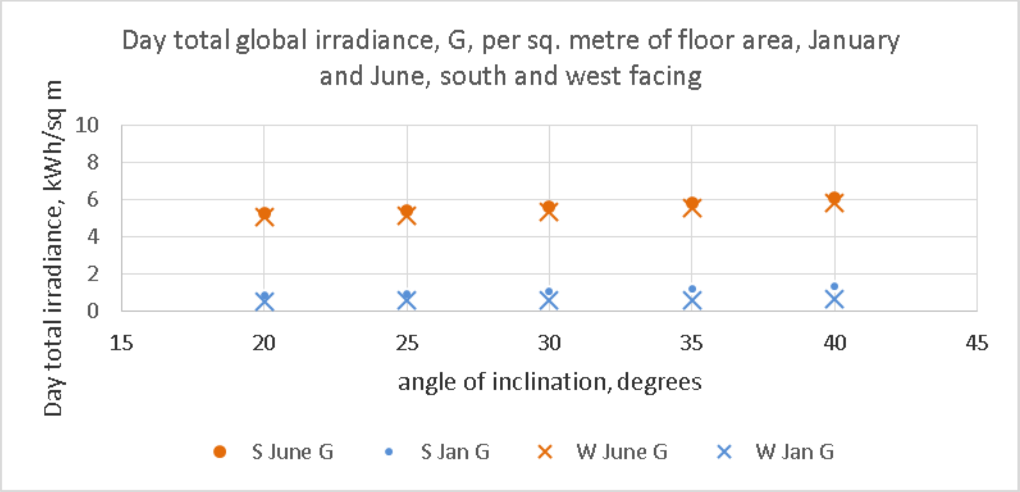


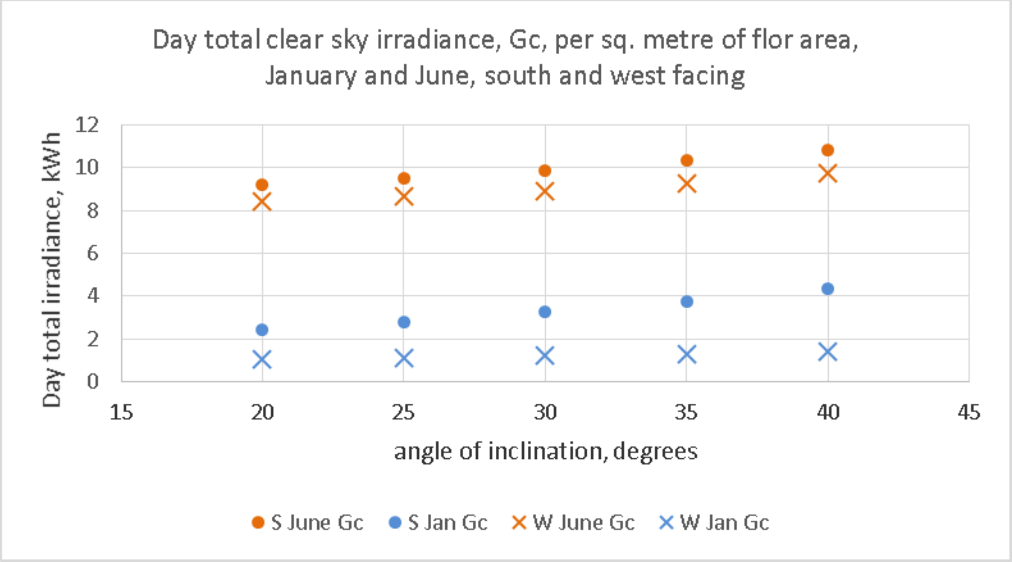


It can be seen that solar irradiance per square metre is insensitive to roof angle, on "average" days. It is completely insensitive on cloudy days (displayed in Appendix 3). On clear days, there is little effect in June, or in January for west facing, though there is a noticeable effect in January for south facing slopes.

If the limit is the horizontal area below the roof (referred to as "floor area"), then the corresponding roof area is slightly larger (irradiation per square metre roof / cosine angle of inclination), and thus irradiation per square metre floor area, is greater than irradiation per square metre roof area. A selection of results are displayed in Figure 17; again, full results are in Appendix 3.

Figure 17 Day total global irradiance per square metre of horizontal surface under the roof ("floor area"), as a function of angle of inclination of roof





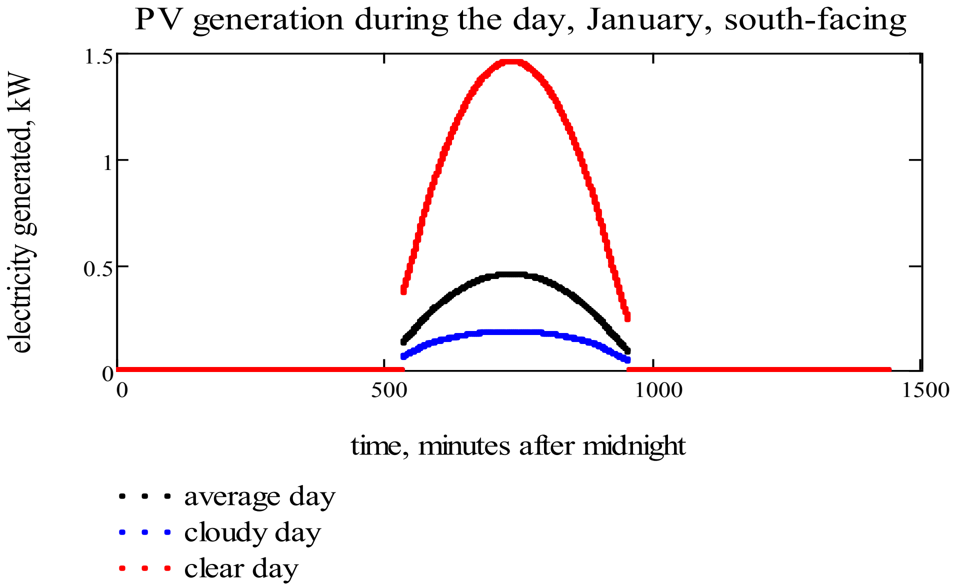
The global irradiance (taken to describe irradiance on "average" days), is hardly affected by changes in roof angle. On cloudy days, there is no effect. However, on clear days in June, for both south and west facing slopes, there is a noticeable effect, though it is not large. In January, on clear days, the irradiance on west facing slopes was not affected by angle of inclination, but angle of inclination had a marked effect on south facing slopes, with steeper slopes receiving higher insolation.

East-facing slopes are expected to behave in a similar manner to west-facing. It is noted that clear days in January are not frequent.

5.2. Patterns of electrical generation from PV panels

Using the inputs described in Section 4.5 and 4.6, electrical generation during the day was calculated. A selection of profiles are displayed below. Figure 18 shows irradiance, urban scenario, January, south and east facing.

Figure 18 PV generation during the day, urban scenarios, January



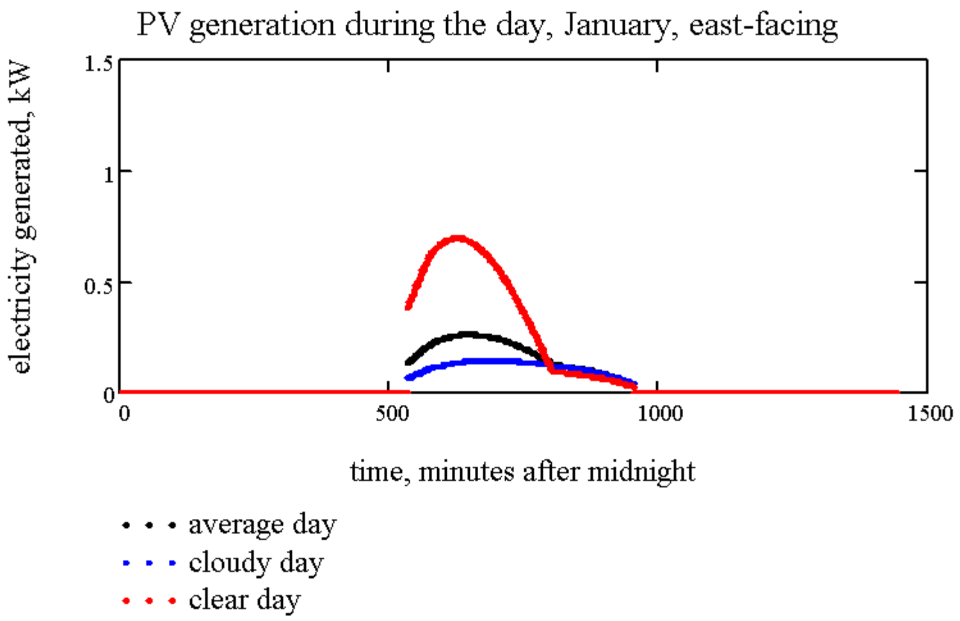


Figure 19 PV generation. Urban scenario, June, south-facing

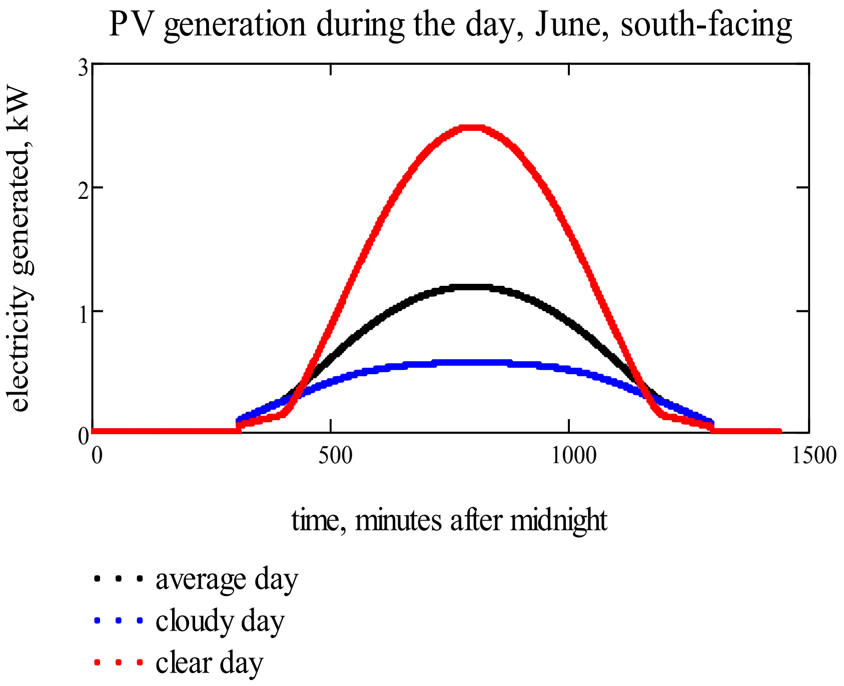


Figure 20 PV generation. Rural scenario, June, combined orientations

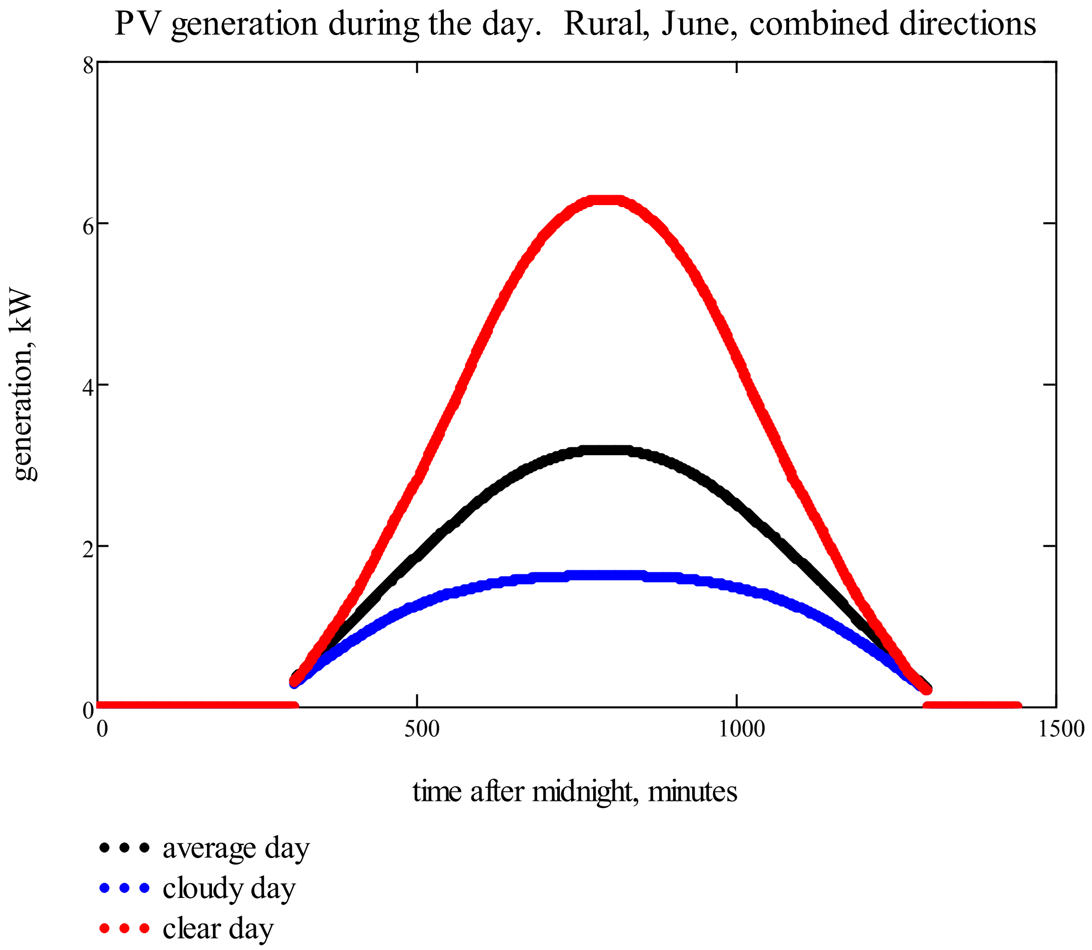


Figure 19 shows June irradiance, south-facing in June, and Figure 20 shows irradiance for the rural scenario, in which orientations are combined, hence a broader peak.

As can be seen, insolation is very sensitive to weather, particularly in January. It is also very sensitive to direction in January, with south, south east and south west facing slopes receiving significant radiation on (rare) clear days; however east and west facing slopes receive significantly less. In June the direction makes much less difference; on cloudy days in both June and January, direction does not affect the irradiation profile.

The quantity of generation for rural scenarios is much larger, by a factor of approximately three, because of the larger area of roof per household.

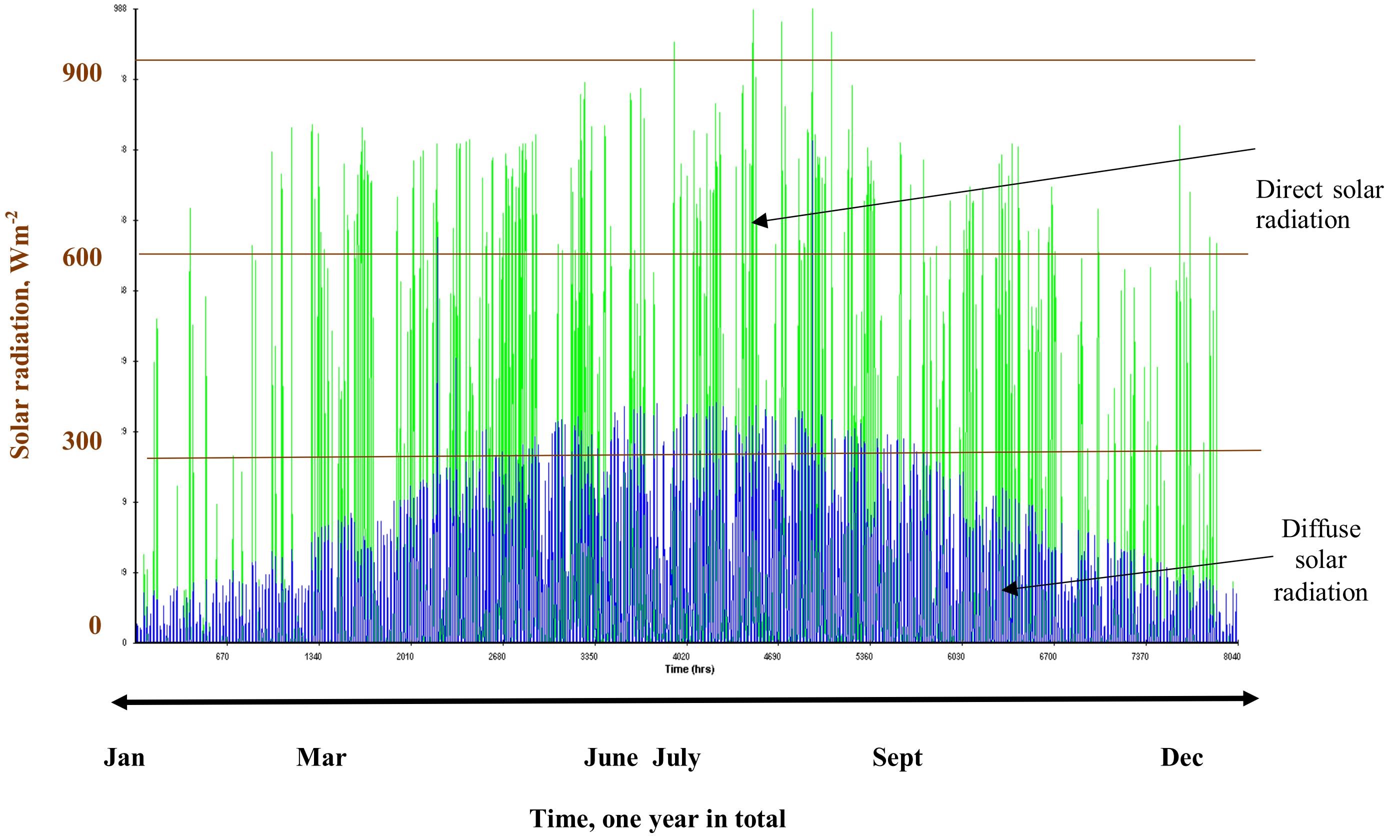
5.3. Comparison of PVGIS data with MERIT climate data. Effect of weather and season on solar irradiation levels

It was considered prudent to consider two questions:

- How well do PVGIS data agree with actual measured weather data?
- How many months need to be studied to approximate annual insolation?

Using climate data for Glasgow in Strathclyde University's Merit programme [65], actual irradiation levels were examined, for the year 1972, which is taken as an example of representative weather. The profile for the year is shown in Figure 21.

Figure 21 Whole year solar irradiation, Glasgow, 1972 (from Merit)



The highest peaks in irradiation increase from around 400W/m^2 in winter, to just over 900W/m^2 in summer. Diffuse solar radiation increases roughly linearly from around 70W/m^2 in December / January, to a summer plateau of around 320 W/m^2 max in June and July. The frequency of sunny days is much higher in mid-season and summer than winter, though at all times of year there is variability in the weather. A sample of four months are displayed in Figure 22 to Figure 25.

Figure 22 Diffuse and direct solar radiation for January 1972 (taken from Merit)

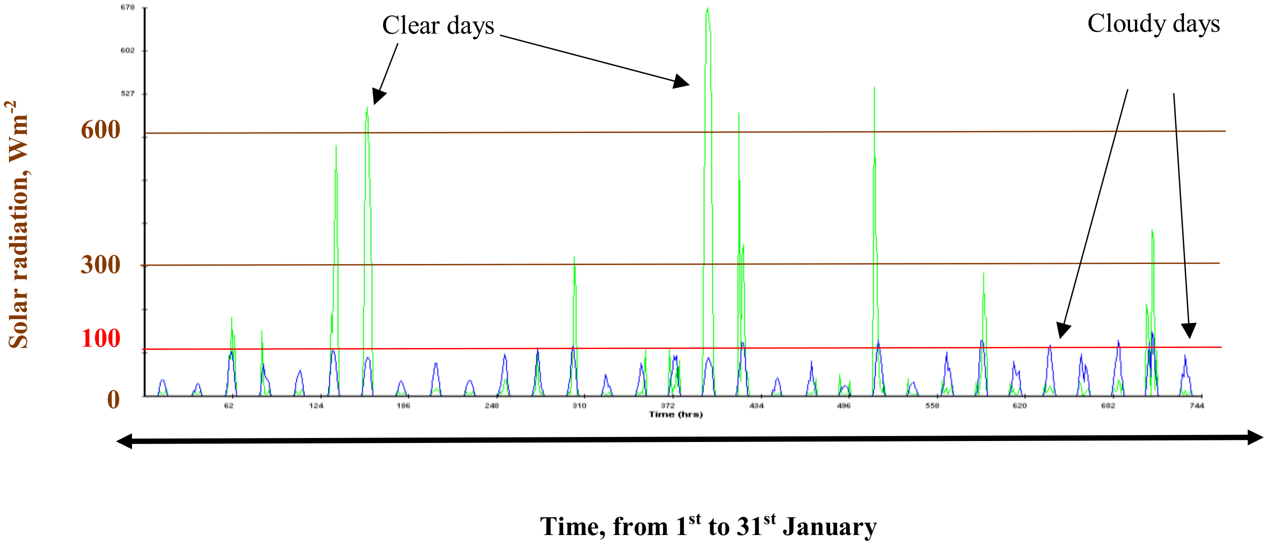


Figure 23 Diffuse and direct solar radiation for March 1972 (taken from Merit)

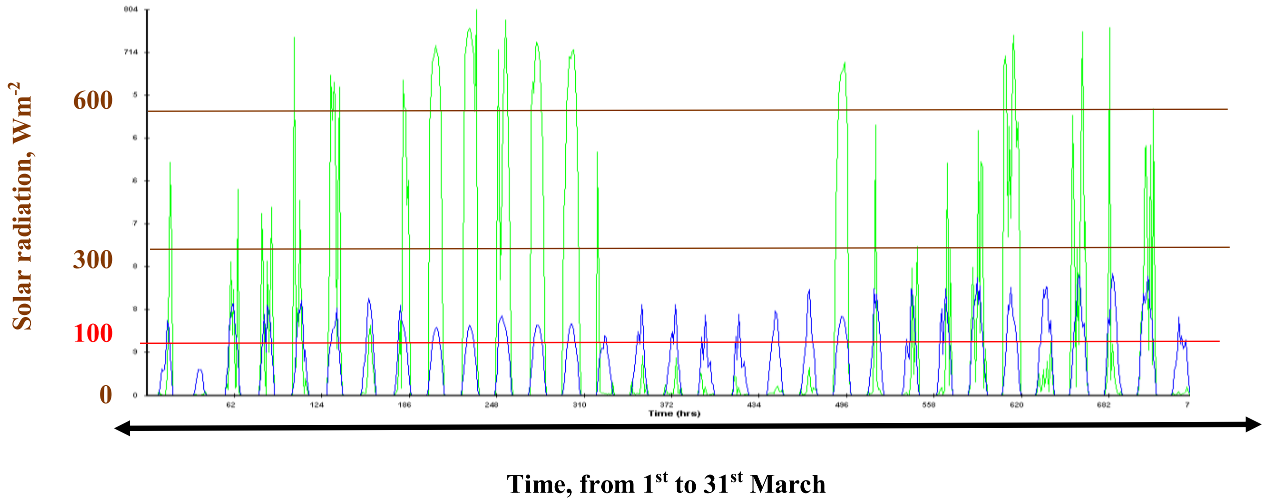


Figure 24 Diffuse and direct solar radiation for June 1972 (taken from Merit)

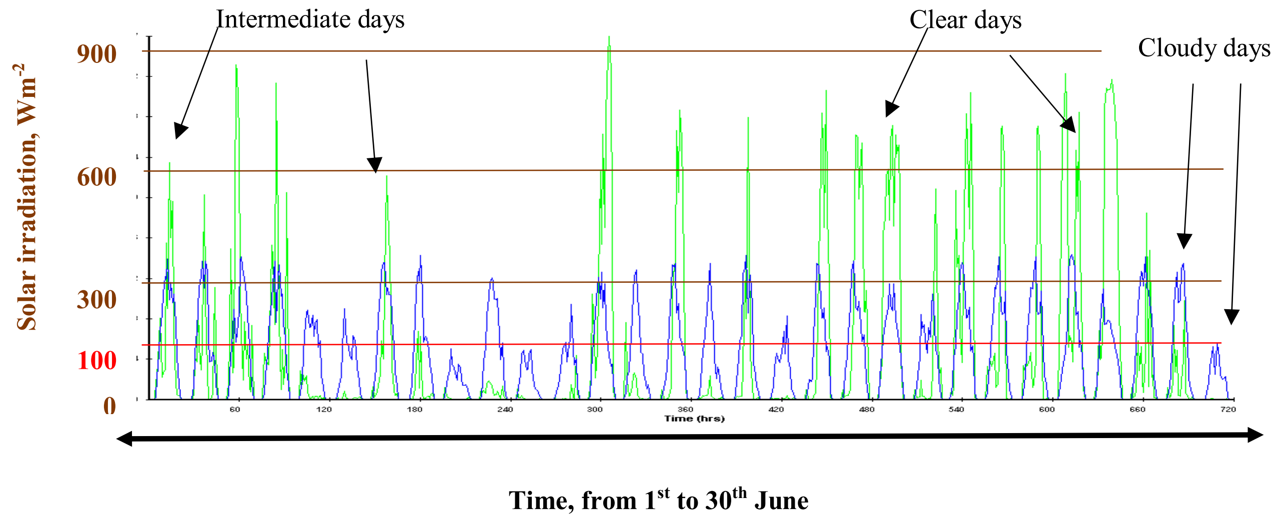
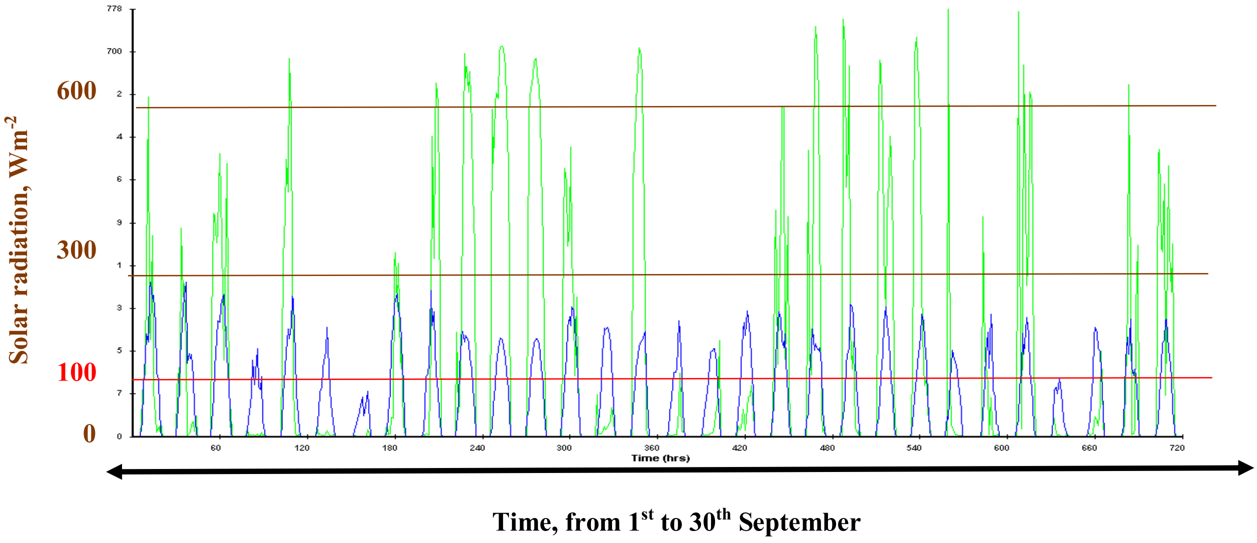


*Figure 25	Diffuse and direct solar radiation for September 1972 (taken from Merit)*



As can be seen, weather and season each have a strong effect on the quantity of solar irradiation. Clear days are particularly infrequent in winter, while the summer is sunnier. However, during over half the months of the year, there were more cloudy days than clear; this occurred during some summer and midseason, months as well as in winter.

*Table 13	Peak (midday) solar irradiation, Glasgow. Comparing 1972 measured data with PVGIS data outputs*

	From Merit database, data for 1972, estimated from graphs					From PVGIS, peak values (around local midday)		
Month	No. clear days[1]	No. cloudy days	No. inter-mediate days	Typical clear peak, Wm^{-2}	Typical diffuse peak, Wm^{-2}	PVGIS clear sky, Wm^{-2}	PVGIS diffuse, Wm^{-2}	PVGIS "global", Wm^{-2}
January	4	21	6	300-700	70	204	64	99
February	9	15	5	400-700	100	353	107	178
March	11	10	10	500-800	150	525	182	309
April	17	4	9	500-800	220	711	204	416
May	10	13	8	500-700	270	800	223	481
June	9	11	9	500-900	250	855	235	445
July	12	11	8	600-900	250	814	235	436
August	8	13	10	500-800	230	708	216	388
September	15	8	7	500-700	200	568	175	319
October	9	14	8	400-700	150	386	129	212
November	7	13	10	400-700	80	242	77	128
December	5	19	7	300-700	60	156	52	79

---

[1] The author's estimate of what was a "clear", "cloudy" and "intermediate" day was used here.

Table 13 summarises solar irradiation peak values at different months: for 1972 from Merit (approximately, read from graphs), and PVGIS predictions. All are for irradiation on a horizontal plane, in Glasgow.

These results are discussed in Section 7.1.

5.4. Demand patterns. 100 runs of Richardson data

Sets of 100 runs were performed, with different input parameters. Profiles of aggregated demands were observed.

The effect of different appliance allocation (for water and space heating) on demand profiles

All the profiles in this section were run with two-person occupancy.

The presence or absence of various types of electric space and water heating had a marked effect on demand profiles. This was particularly the case for storage heaters, which cause a 10kW load during the night, in January, but not in June. Additional loading of electrical water and space heating cause a significant effect in January. In June, electric space heating does not affect the profile, but water heating does. Even removing the electric shower slightly reduces demand, and removes some of the "spikiness" from profiles. These profiles are appended in Appendix 4.

Urban scenarios: no electric heating or hot water. The effect occupant number on aggregated demand profiles

Some investigations were done on the effect of different numbers of occupants. One example, an urban scenario, with no electric space or water heating, is shown in Figure 26.

Others are appended in Appendix 4.

Two "mixed occupancy" scenarios were devised, "Ballindalloch" and "Onslow" with occupant numbers as detailed in Table 6, and appliance ownership as detailed in Table 7. "Ballindalloch" scenario (three-bedroom flats) has a more households with large occupant numbers; "Onslow" scenario (one / two bedroom flats) is predominantly single and two-person occupancy, with a small number of larger households. The profiles are shown in Figure 27 and Figure 28.

Figure 26 January, 100 runs. Urban scenario (no electric heating or hot water). Aggregated demand profile during the day, for different numbers of occupants

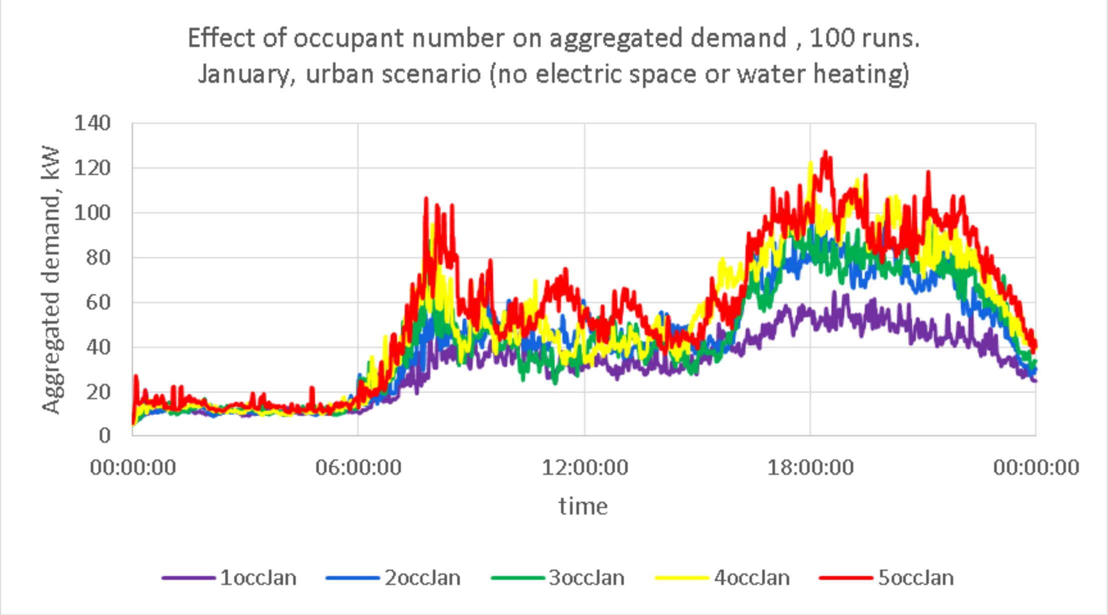


Figure 27 January and June, mixed numbers of occupants, "Ballindalloch" scenario

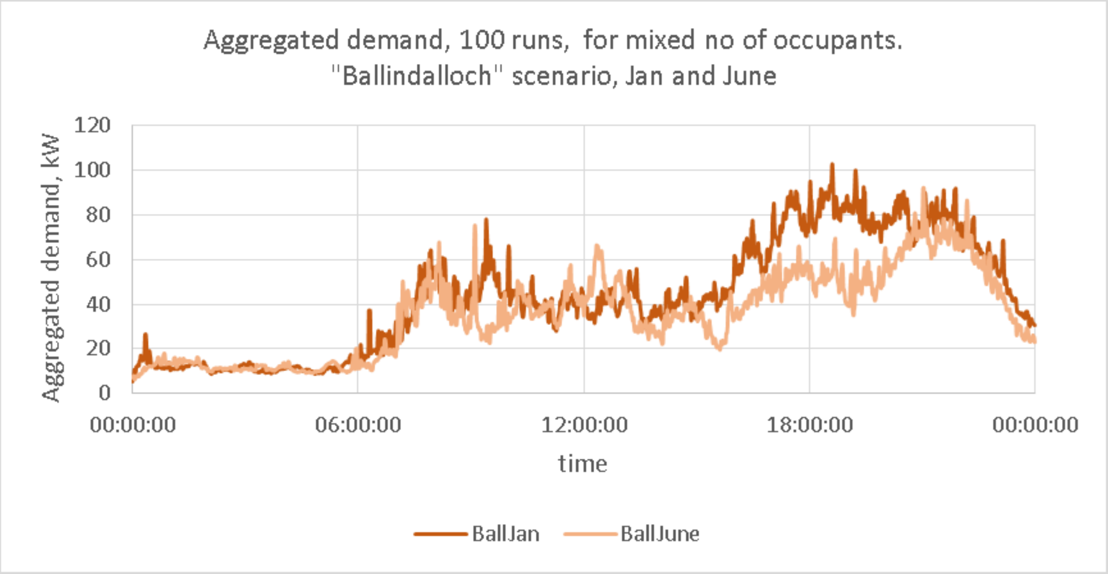
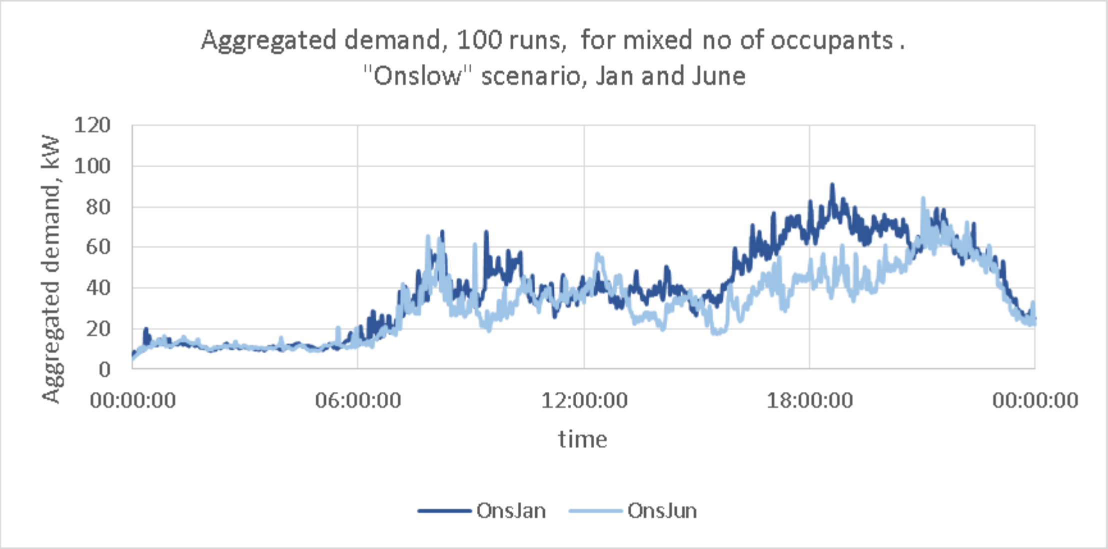


Figure 28 January and June, mixed numbers of occupants, "Onslow" scenario

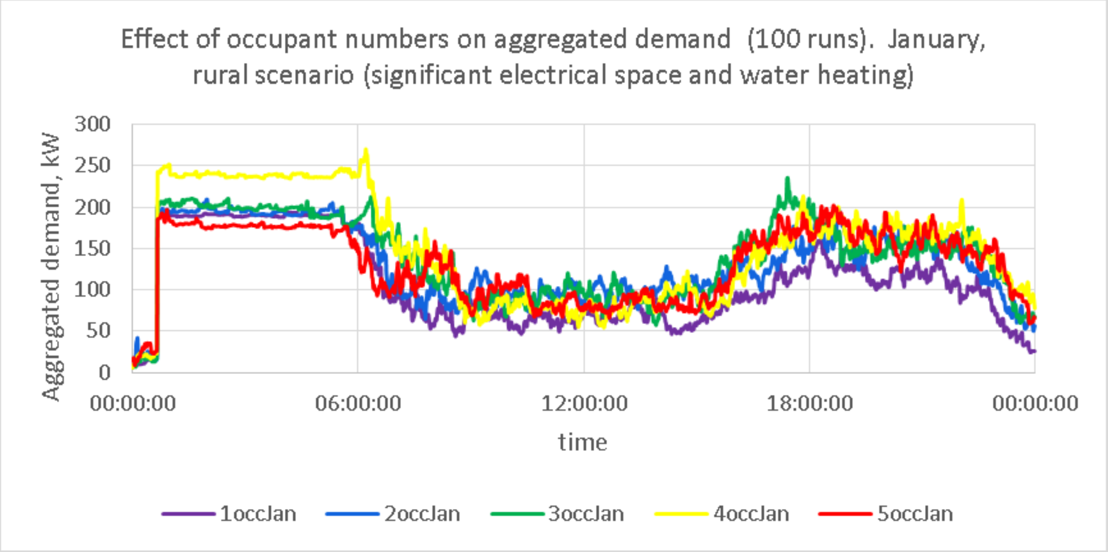


Despite the difference in numbers of occupants, the difference in aggregated electrical demand is surprisingly small. It was thus decided to perform detailed modelling on "Ballindalloch" scenario only.

Rural scenario: significant electrical and space heating loads. The effect of occupant number on aggregated demand profiles.

For rural scenarios, in which higher allocation of electrical heating appliances is assumed (as shown in *Table 7*) similar investigations were performed to investigate effect of number of occupants. One example is shown in *Figure 29*; more details are displayed in Appendix 4.

Figure 29 January, 100 runs. Rural scenario (significant electric space and water heating). Aggregated demand profile during the day, for different numbers of occupants



Scenarios were devised of mixed numbers of occupants and appliance ownership (detailed in Table 6 and Table 7). Scenarios “Rural 1” and “Rural 2” are displayed in Figure 30 and Figure 31 below. “Rural 2” is the same as “Rural 1” except there is no storage heating. (A separate run for “Rural 2” was only done for January; for June the same dataset is used.)

Figure 30 January and June, mixed numbers of occupants, "Rural 1" scenario

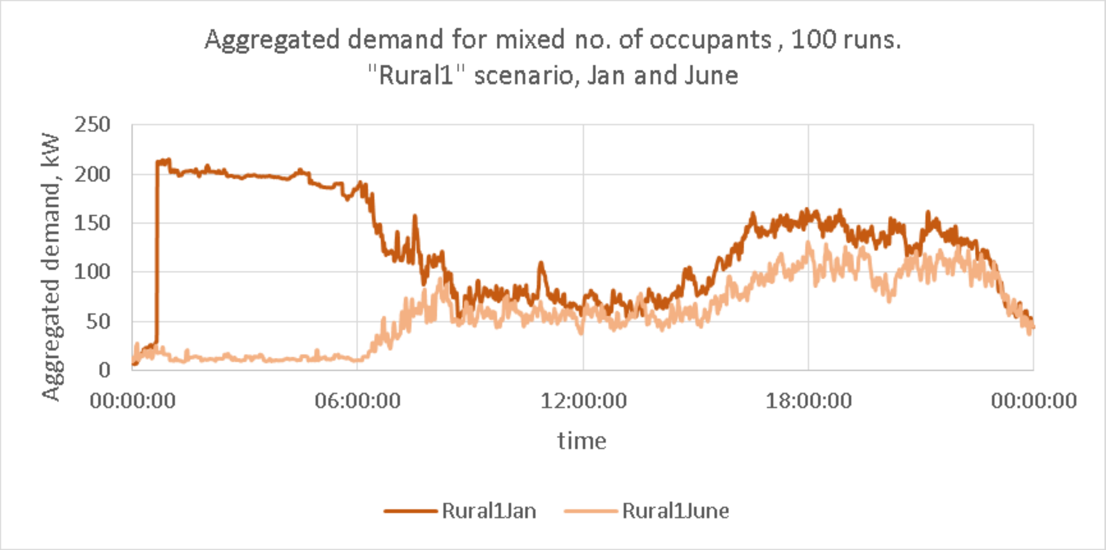
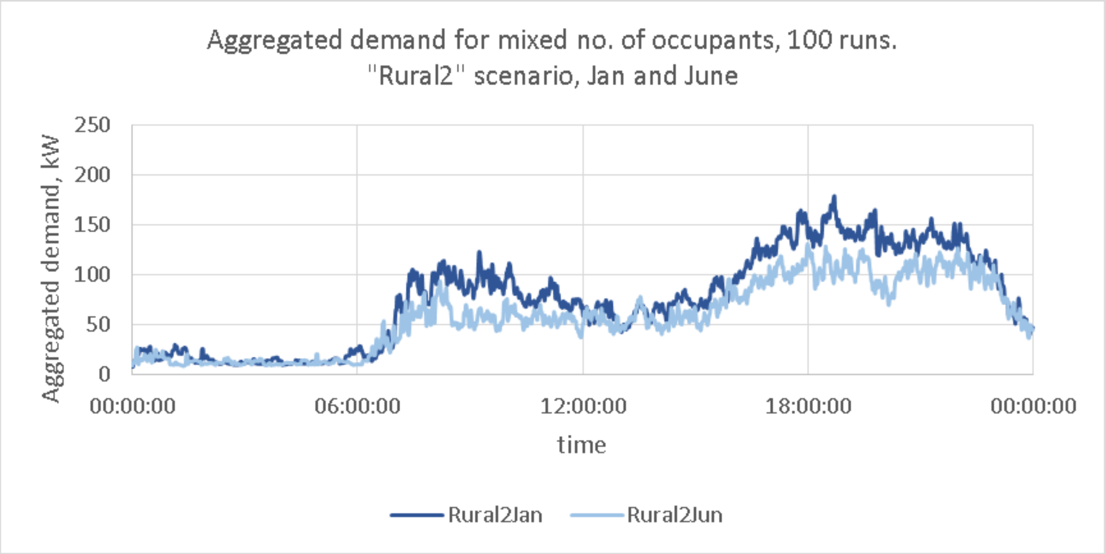


Figure 31 January and June, mixed numbers of occupants, "Rural 2" scenario



5.5. Comparisons of individual and aggregated demand profiles, of different sizes of groups of runs

One hundred runs, Ballindalloch scenario

Individual demand profiles for 100 runs, Ballindalloch scenario, are displayed in Figure 32 (January) and Figure 33 (June). Aggregated demand profiles for these runs are displayed previously, in Figure 27, in Section 5.4.

Figure 32 Individual demand profiles of 100 runs, Ballindalloch scenario, January

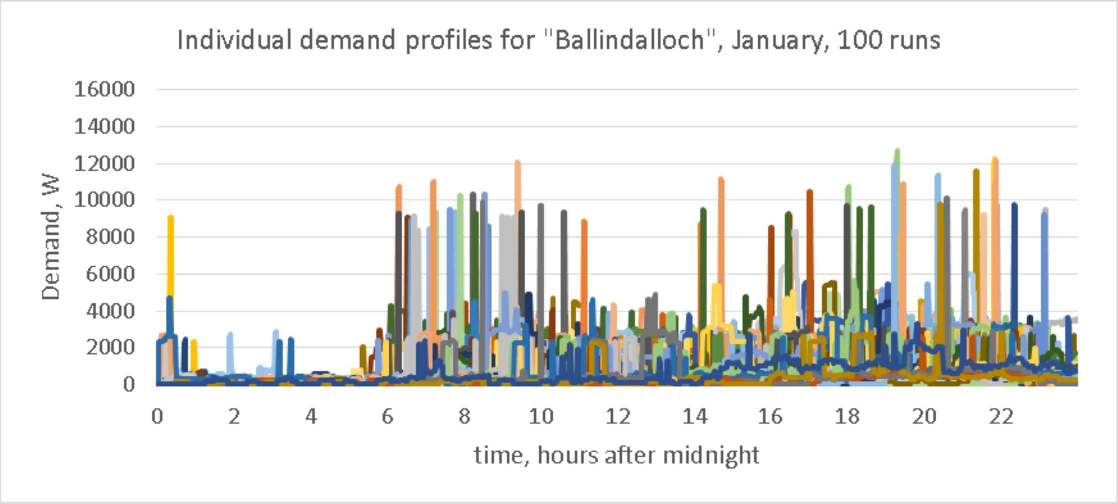
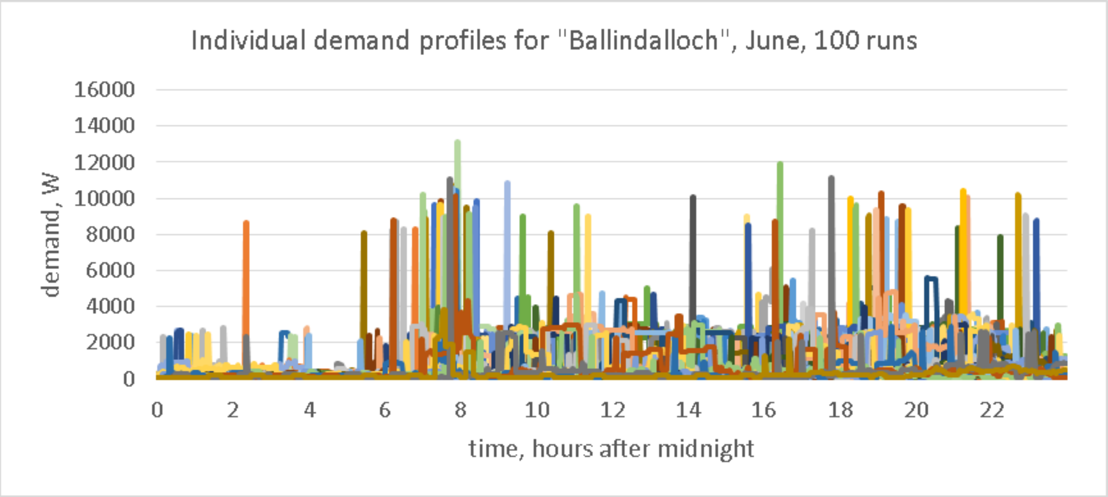


Figure 33 Individual demand profiles of 100 runs, Ballindalloch scenario, June

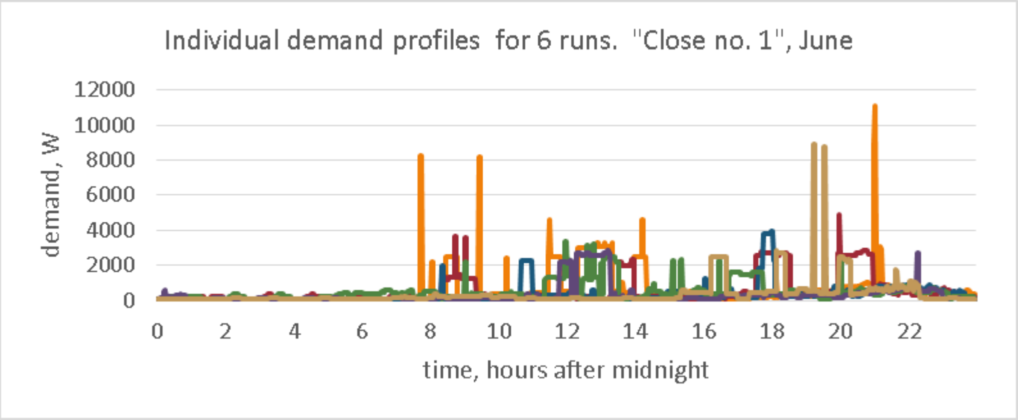


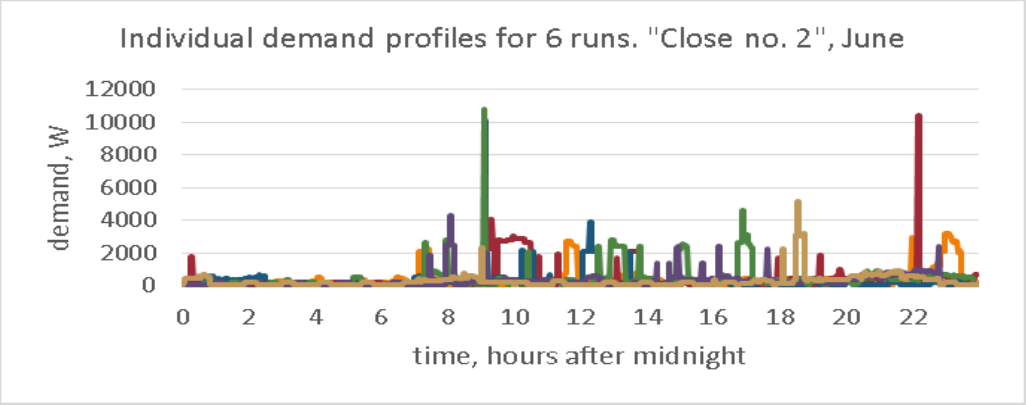
Six runs, Ballindalloch scenario

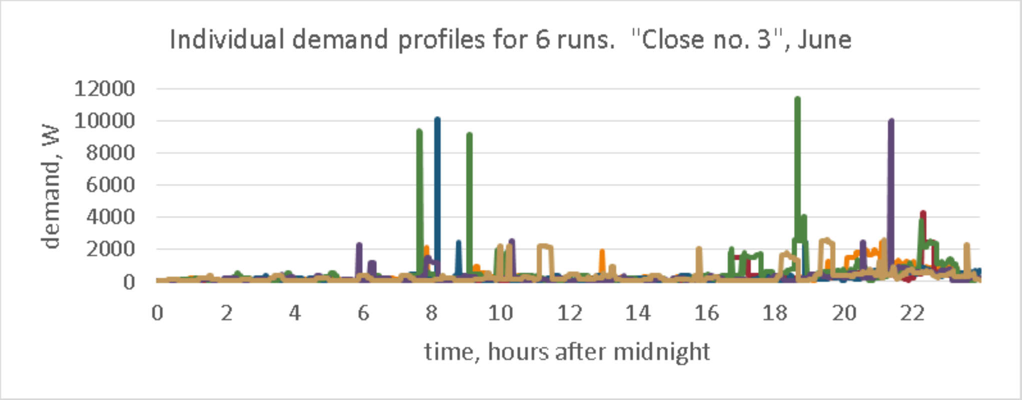
Four sets of six runs were examined. These runs could represent four individual "closes" (groups of flats sharing a common stairwell, and with shared ownership of the roof). Runs were selected from the "Ballindalloch 100" dataset, with numbers of occupants close to the overall proportions of 1/2/3/4/5 occupant households displayed in

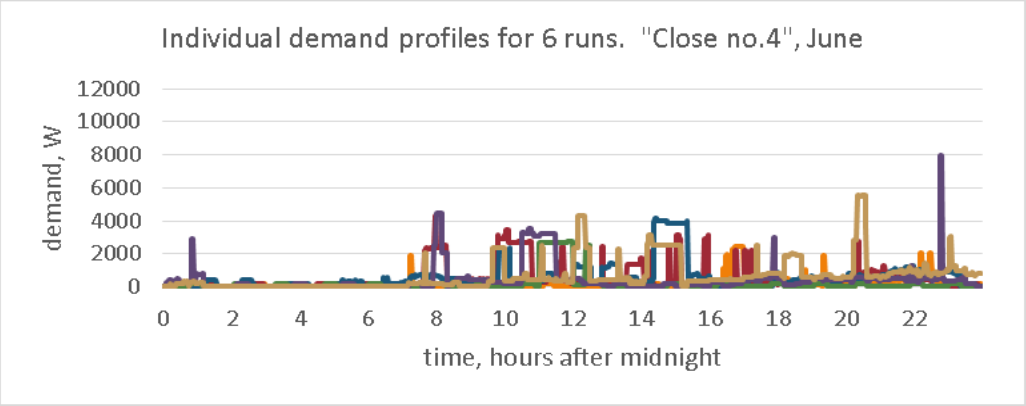
Table 6. The actual numbers of occupants in the individual closes are displayed in Appendix 5. The June profiles are displayed in Figure 34 and the January ones are in Appendix 5.

Figure 34 Individual demand profiles of four groups of six runs, Ballindalloch scenario, June



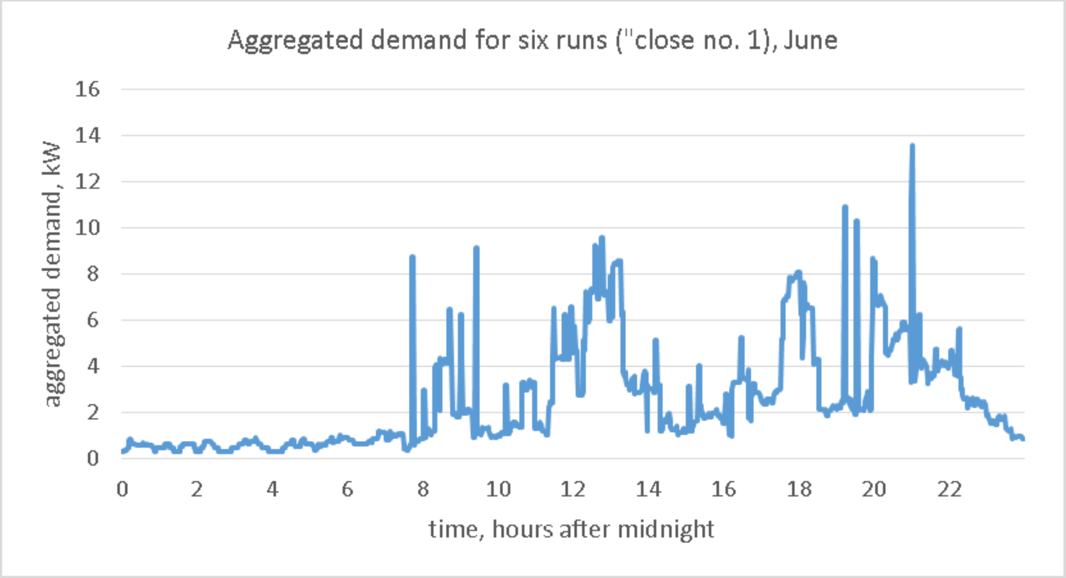






An example of one the aggregated demand profiles is shown in Figure 35. Another is displayed in Appendix 5.

Figure 35 Aggregated demand of 6 runs ("close no.1"). Ballindalloch scenario, June

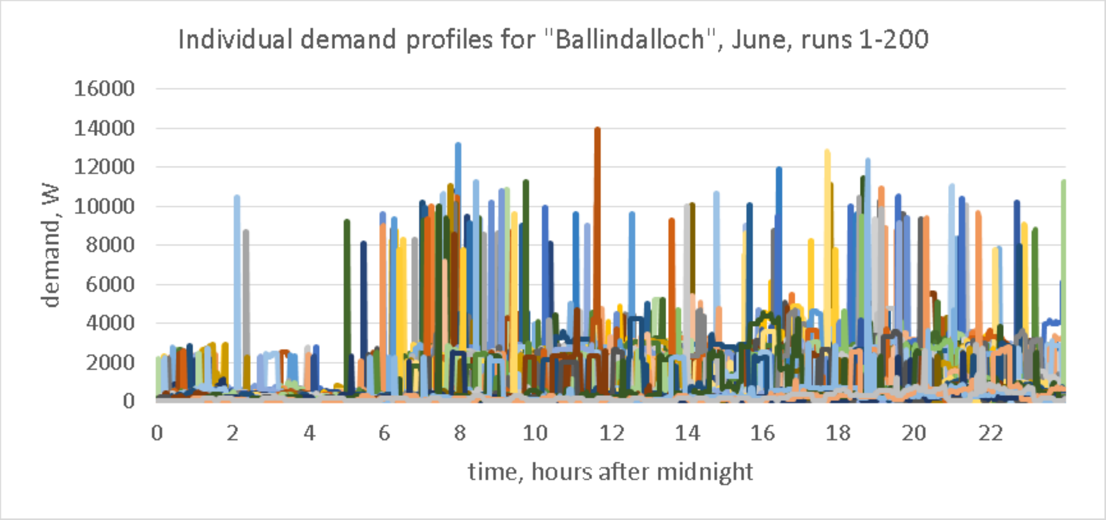


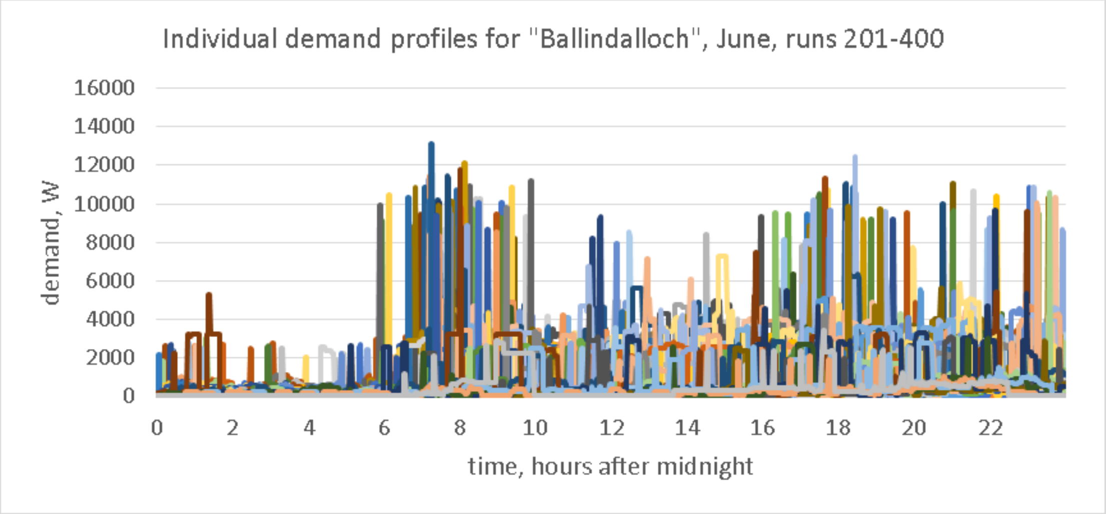
Six hundred runs, Ballindalloch scenario

A compilation of 600 runs was performed, shown in Figure 36. (Charts broken down into three figures of 200 runs each).

Aggregated demand for the above 600 runs is displayed in Figure 37.

Figure 36 Individual demand profiles of 600 runs (Shown in three charts each of 200 different runs from the 600). Ballindalloch scenario, June





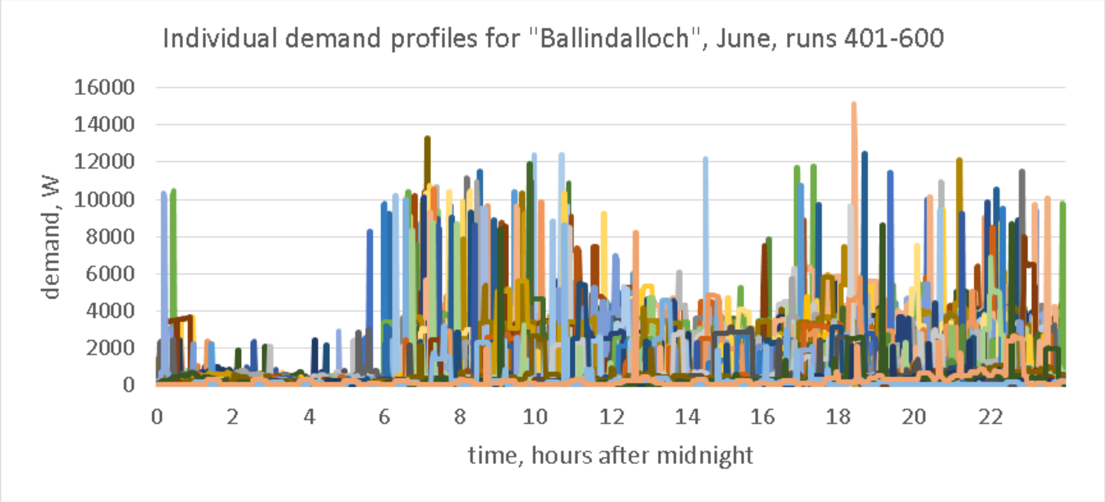
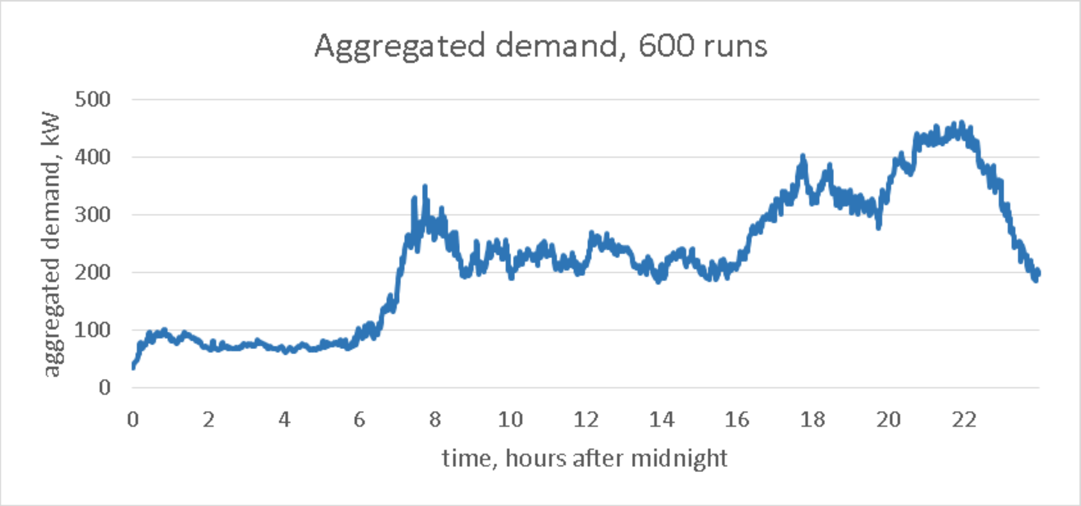


Figure 37 Aggregated demand profile for the 600 runs. Ballindalloch scenario, June



Overall observations

All the above graphs show examples of both coincident and non-coincident demands. For most runs there is minimal demand (around 50W) during the night, with very occasional greater demand in a run. During the day, the demand pattern is dominated by draws of around 2-4kW, lasting for prolonged periods, and for occasional demands of 2-10kW lasting only a few minutes. It is unusual for the very transient peaks to be coincident (in groups of up to 100 runs), but there is considerable coincidence of the longer-duration demands, particularly during the morning and evening.

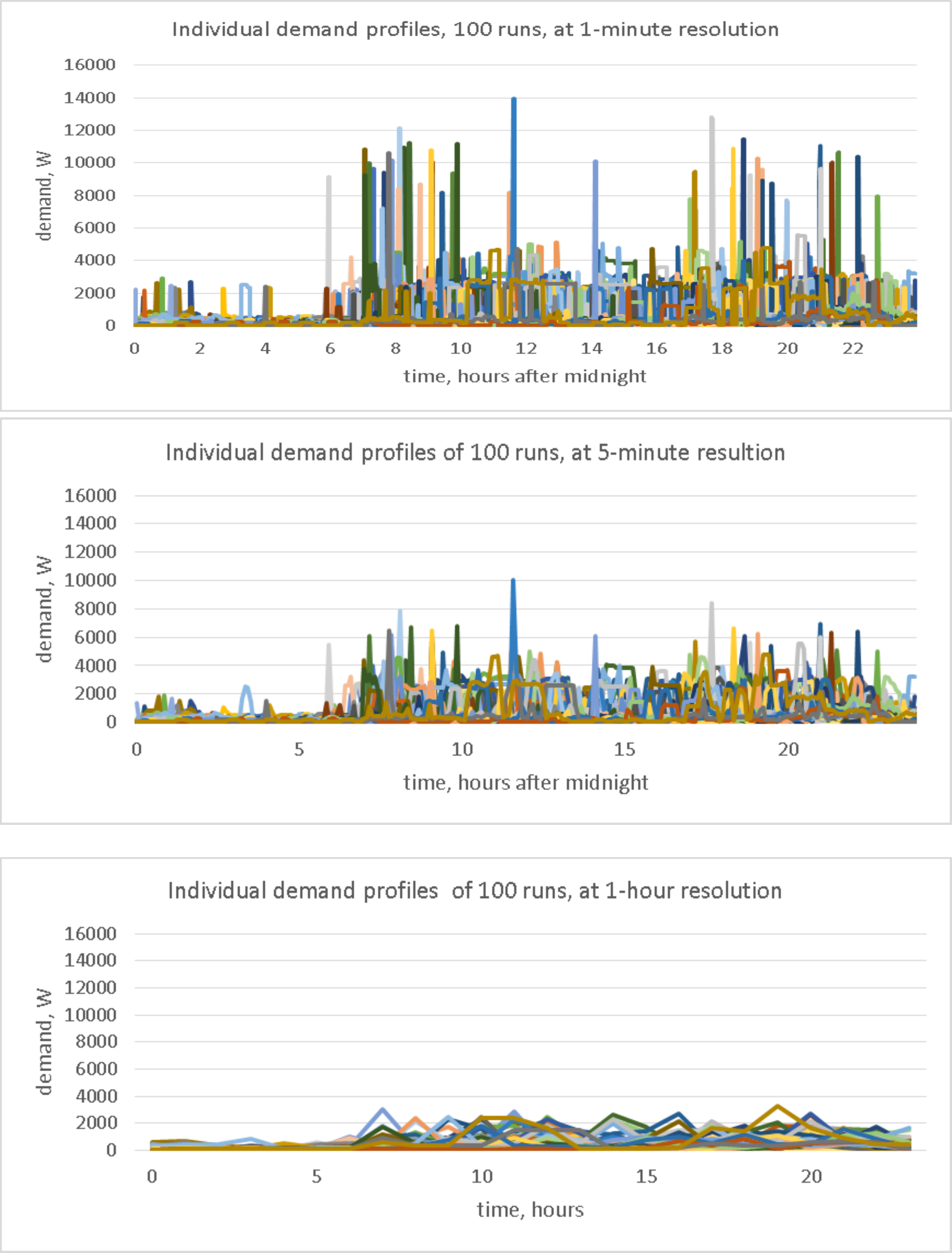
As expected, an aggregation of six runs (Figure 35) is still very “spiky”. The aggregation of 600 runs (Figure 37) is smoother than the 100-run aggregations (Figure 27 in Section 5.4), though the difference is not great.

5.6. Comparison of different temporal resolutions

Section 4.8 describes the investigation into the effect of temporal resolution on demand patterns.

For the urban Ballindalloch scenario, 100 demand profiles, for June, were viewed in their original 1-minute resolution. The same datasets were smoothed to 5 minute and one hour resolutions. The individual demand profiles at the three temporal resolutions are shown in Figure 38. Their aggregated demand profiles are shown in Appendix 20.

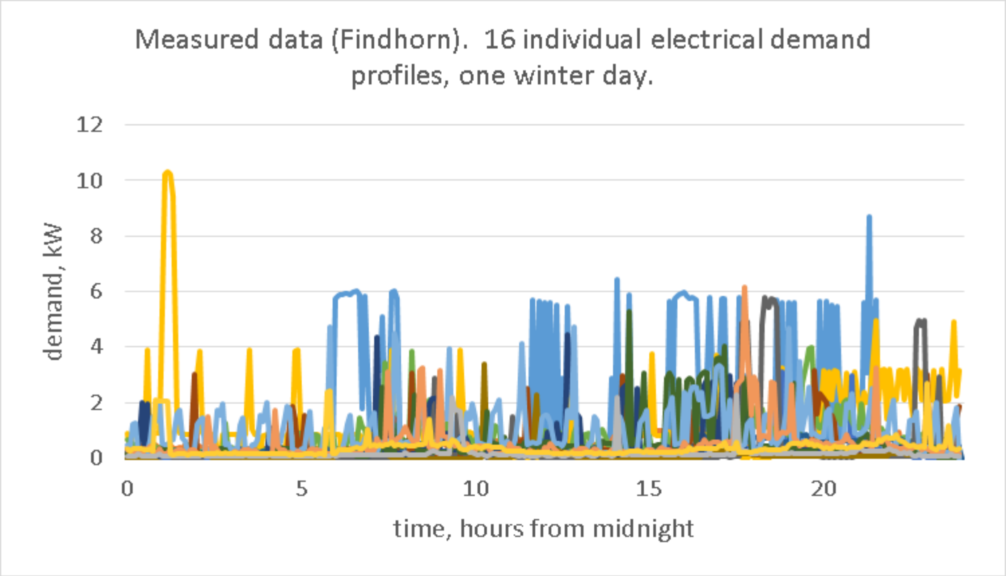
Figure 38 100 individual demand profiles (Ballindalloch scenario, June) at three different temporal resolutions: 1-minute, 5-miunte and 1-hour

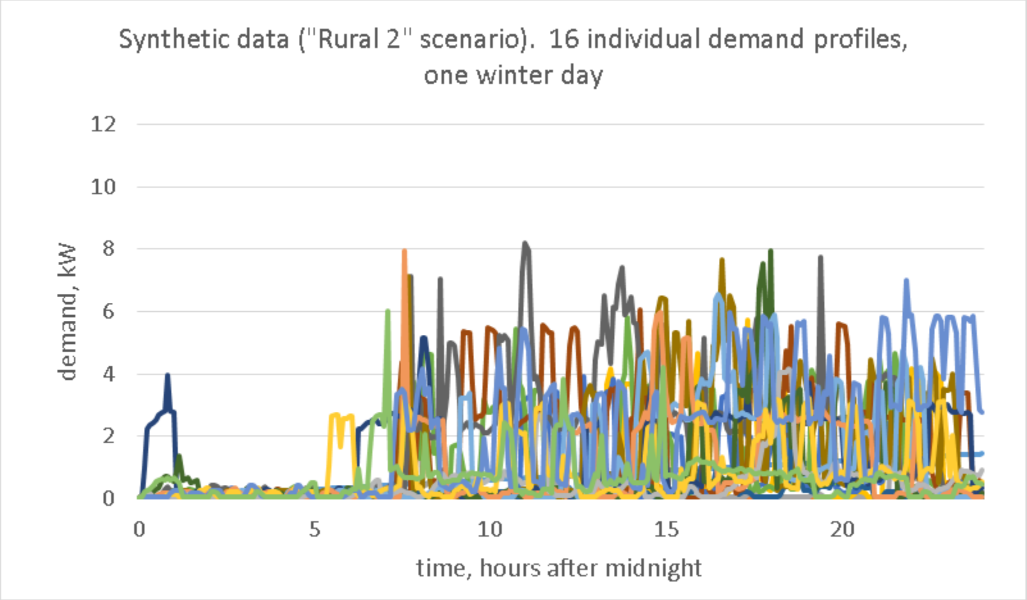


5.7. Case study: comparison with measured data from Findhorn

Section 4.9 describes the case study, in which real measured data have been obtained, and compared with a control group of synthetic data.

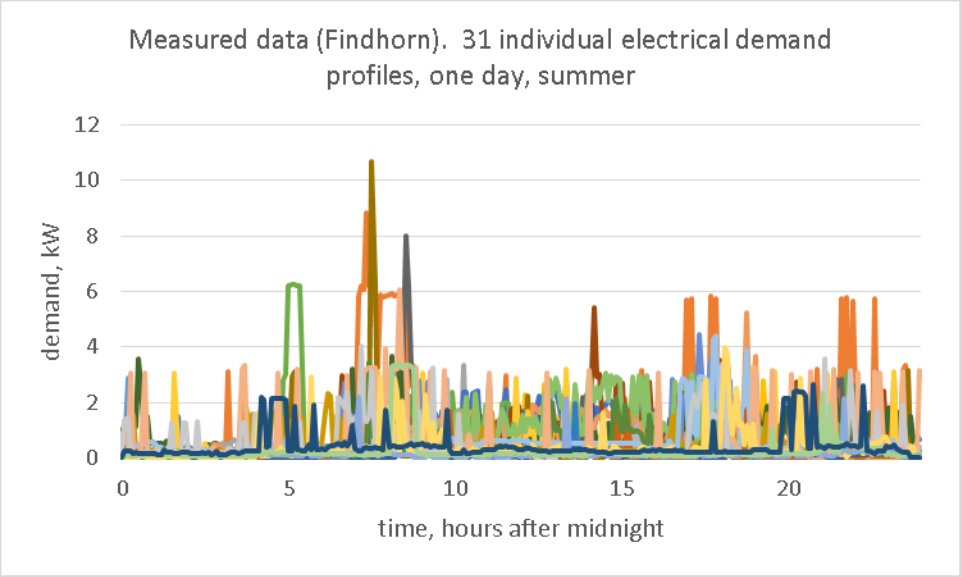
Figure 39 Individual demand profiles for 16 properties, winter day. Measured (Findhorn) and synthetic data

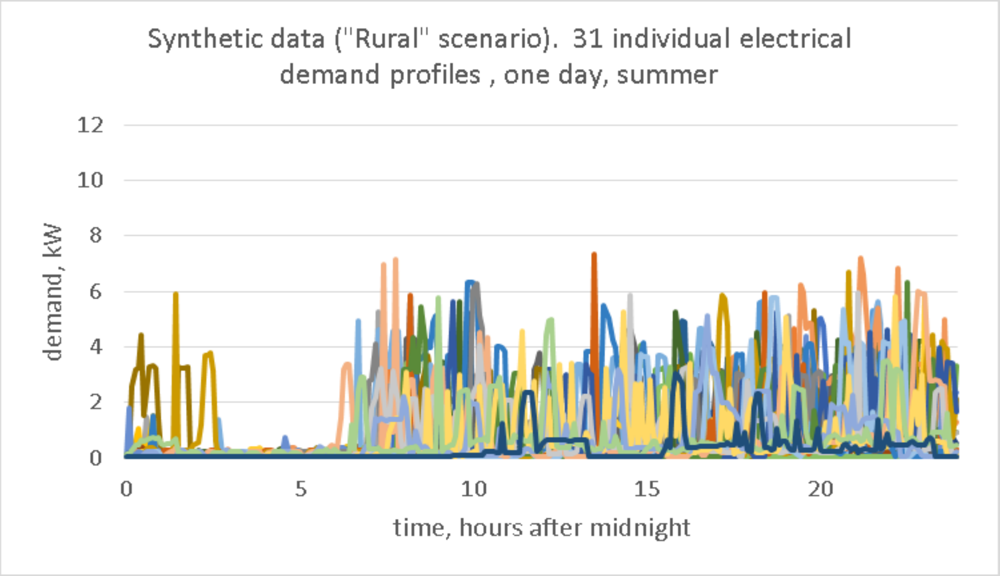




The individual demand profiles, for both the case study (measured data) and comparison group (synthetic data), are displayed in Figure 39 (winter) and Figure 40 (summer).

Figure 40 Individual demand profiles for 31 properties, summer day. Measured (Findhorn) and synthetic data





Aggregated demand profiles, for measured Findhorn data, and the comparison group, are displayed in Figure 41(winter) and Figure 42 (summer).

Figure 41 Aggregated demand profiles for 16 properties, winter day. Measured and synthetic data.

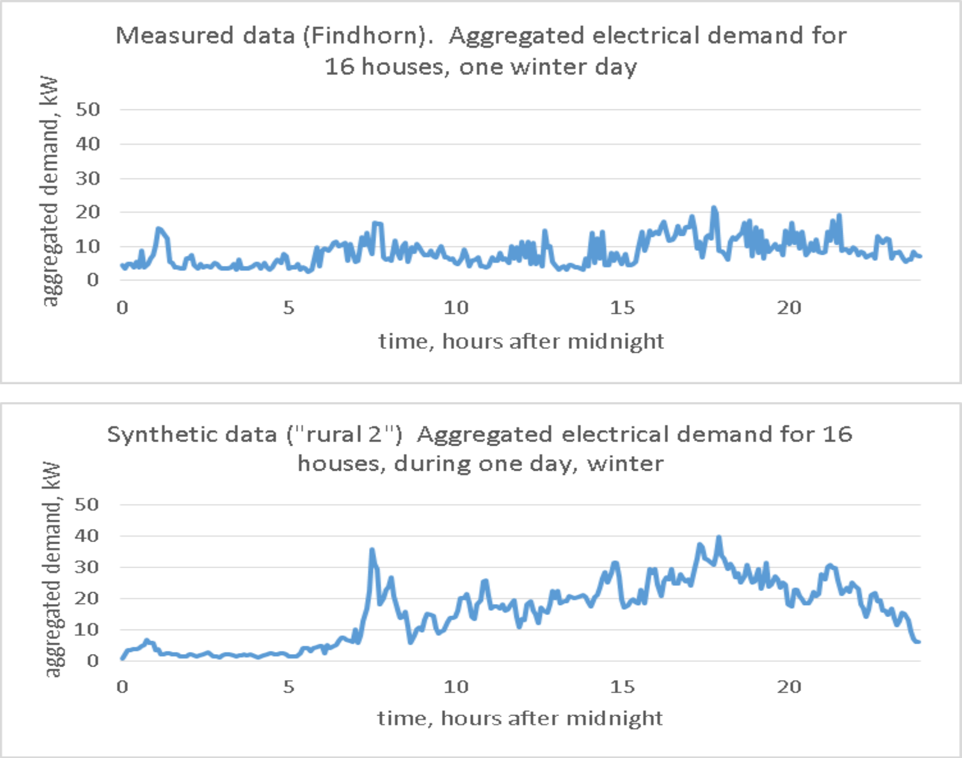
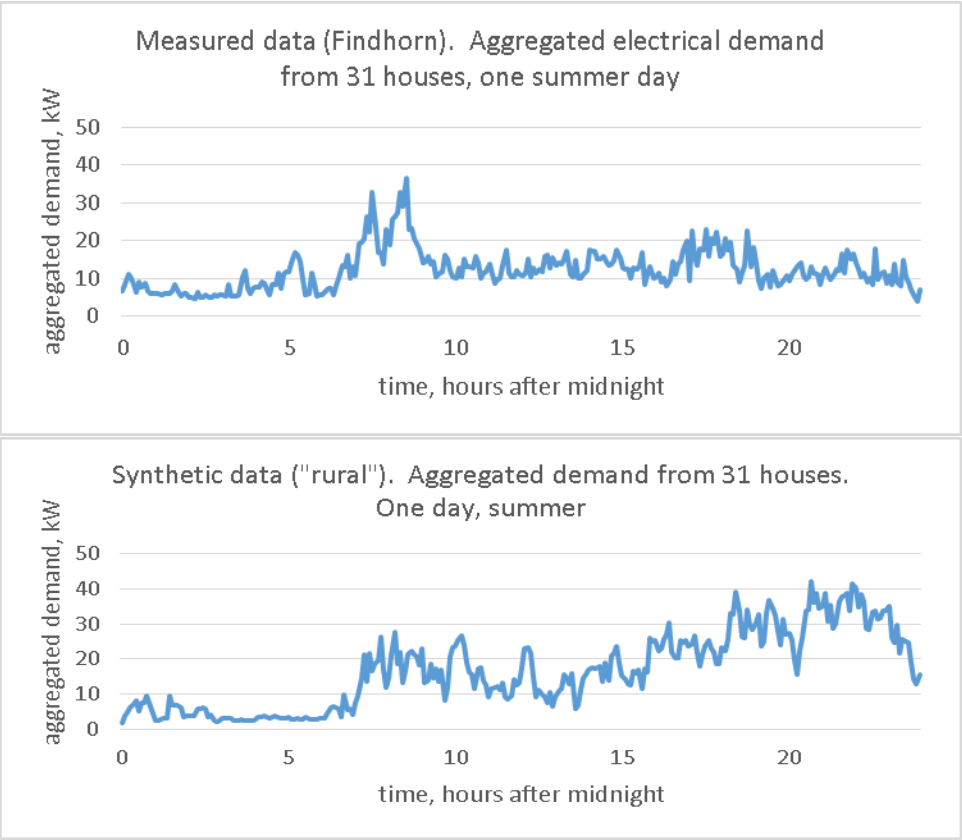


Figure 42 Aggregated electrical demand profiles for 31 properties, summer day. Measured and synthetic data.



6. Main results

6.1. Overview of Main Results

This section presents the outputs from the main calculation model, which evaluated excesses and deficits in electrical generation at every time step during the day for every run, and from which day totals of excesses and deficits were derived. Sections 6.2 and 6.3 give an overview of results of 100 runs for the urban and rural scenarios. Section 6.4 presents considerations on the initial state of charge (SOC) of the battery, which may depend on the weather the preceding day, Section 6.5 shows the effect of type of storage, and 6.6 presents results of investigation into the effect of the size of "community", including large and smaller than the 100 runs ("houses") used for the main calculations. Section 6.7 presents results of from data of different temporal resolutions, and 6.8 reports on a case study using measured data from the village of Findhorn, for comparison with synthetic demand data. The later sections move into financial evaluations: section 6.9 evaluates day total savings in the electricity purchased from the grid, in summer and winter. From these results, estimations of annual savings, in kWh of electricity, and associated costs, are made. Section 6.10 presents information on costs of storage, and section 6.11 presents information relevant to estimation of costs of aggregation. A comparison of estimated costs and benefits of aggregation and storage is made in section 6.12.

6.2. Urban Ballindalloch scenario, 100 runs

Generation and demands

In the winter, demand considerably exceeds generation, in all but exceptionally low-demand runs. However, for south (and also south-east and south-west facing slopes) on a clear winter day, generation can be as high as 70% of mean demand. This is not the case for east and west-facing slopes. Therefore considerable deficits are inevitable.

In summer, generation and demand are more closely matched. Generation exceeds mean demand on average days, and is over double mean demand on clear days, whereas on cloudy days, generation is a little lower than mean demand. Table 14 summarises a selection of results.

Table 14 Generation and demand, urban scenario

Month	Scenario	Day total demand, kWh			Day total generation, kWh					
					South-facing			East-facing		
		mean of 100	min of 100	max of 100	average day	cloudy day	clear day	average day	cloudy day	clear day
Jan	Ballindalloch	10.4	1.4	19.4	2.4	1.0	7.4	1.2	0.8	2.5
June		8.5	3.1	18.9	11.6	6.7	20.4	11.0	6.7	18.3

Effect of orientation on excesses and deficits in generation, without storage

In winter, small excesses in electrical generation are seen in some conditions, which are very sensitive to orientation and weather. South, south-east and south-west facing slopes have modest mean day total excesses of around 1kWh on an average day, and 4-5kWh on a clear day. Excesses in other conditions are very much smaller. Deficits in generation were around 8-10kWh mean day totals, with the lower values for south, south-east and south-west-facing slopes on clear days. These are displayed in Appendix 15.

In summer, mean day total excesses of around 8kWh are seen on average days, which are very sensitive to weather conditions. (Mean day total excesses are 4kWh on cloudy days and 15 kWh on clear days). Mean day total deficits of around 5kWh are seen, which are much fairly insensitive to the weather than the excesses. Orientation does not have a marked effect, though it is interesting to note slightly lower excesses for west than east-facing roofs on a clear day. These are all shown in Appendix 15.

The effect of storage and aggregation on day total excesses and deficits

<u>January, south facing, on an “average” day.</u>

The 100 runs have a range of day totals for deficits and excesses in generation. Figure 43 displays the *mean* of the 100 day total deficits, (blue bar), for an “average weather" day. The day total deficit in generation *from an aggregation of the 100 runs*, on the same "average weather" day is also displayed (black bar).

An initial minimum state of charge (SOC) of battery is assumed here, typical of the state of charge at the end of an average or cloudy day in January. (The mean SOC after a clear day is slightly higher, though the difference is small.)

Figure 43 Effect of Li battery storage on deficits: Ballindalloch scenario, January. Mean day total deficits of 100 individual runs, and day total deficit of an aggregation of the same 100 runs.

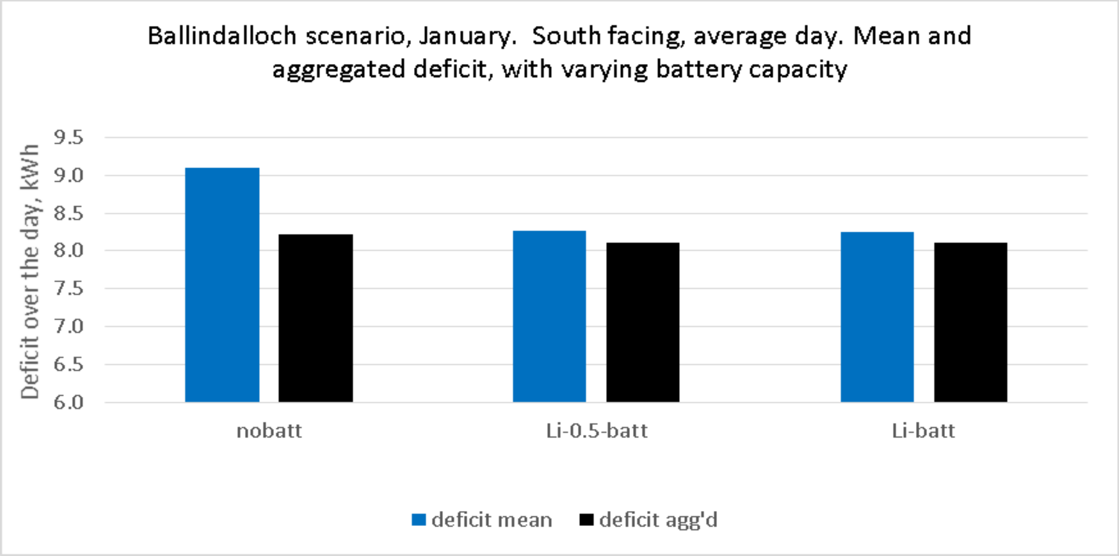


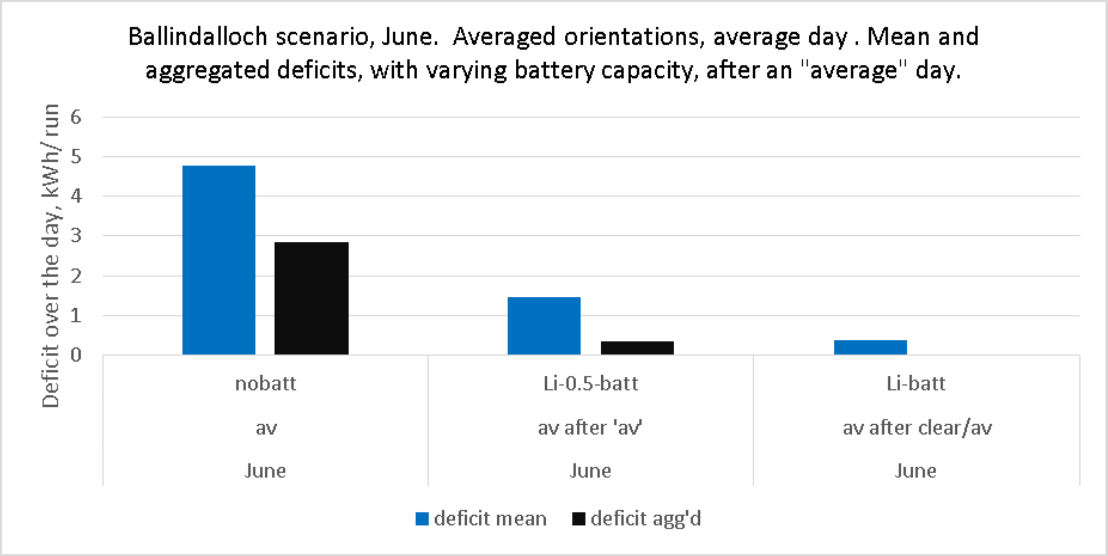
Figure 43 shows that adding half a lithium battery, on an individual house basis, reduces mean day total deficit by a little under 1kWh. Adding further storage makes virtually no difference. An aggregation of the same runs, even without storage, has approximately 1kWh lower day total deficit than the mean day total deficit of the individual runs. Installing half a lithium battery storage per household on the aggregation, causes a minimal further reduction in deficit. Installing further storage on the aggregation has no effect.

On cloudy days, there is very little solar generation, so little effect of storage or aggregation. On clear days, for south-facing slopes (and to a lesser extent, south-east and south-west), aggregation and storage bring greater reductions in deficits, as shown in Appendix 16.

June, "averaged" orientations, average weather day

The 100 runs, with June demands and generation, have a range of excesses and deficits in day total generation. Figure 44 displays the *mean* of the 100 day totals of deficit (in blue) and the day total deficit *for an aggregation* of the same 100 runs (in black). In this case, it is assumed that the preceding day had "clear" or "average" weather.

Figure 44 Effect of Li battery storage on deficits: urban scenario, June, an "average" day after an "average" or clear day



Very similar results were also found modelling the effect of lead batteries, which are displayed in Appendix 17.

6.3. Rural scenarios, 100 runs

Generation and demand

In both rural scenarios, the generation is three times greater than in the urban scenarios, and demand, which includes for water and space heating, are greater. The day totals of generation and demand are shown in

Table 15.

Excesses and deficits in electrical generation, on average, clear and cloudy days, are displayed in Appendix 18. These runs took an initial state of charge of the battery, as the mean / median state of charge, following "average" conditions" the previous day. There is always variation between individual runs; in some cases the final state of charge. The main points are described below.

Table 15 Generation and demand: rural scenarios

Month	Scenario	Day total demand, kWh			Day total generation, kWh		
		Mean of 100	Min of 100	Max of 100	Average day	Cloudy day	Clear day
January	Rural 1	30.0	4.1	99.9	14.4	2.7	5.3
	Rural 2	18.2	5.2	40.6			
June	Rural 1	8.5	3.1	18.9	33.9	20.2	58.5

The effect of storage and aggregation on day total excesses and deficits

Summer

As Table 15 shows, the generation in summer significantly exceeds demands, even on cloudy days, and much more so on average and clear days. Thus, there are considerably excesses in generation.

Mean day total excesses are 26kWh on an "average" day, 50kWh on a clear day and 14kWh on a cloudy day, without aggregation or storage. Actual runs have a range of values. Aggregating and installing batteries, of different sizes, reduces day total excesses by a few kWh. This still leaves significant excess generation in most of the runs. Far larger storage capacity would need to be installed to make any significant difference to this.

Nevertheless, there are still deficits in demand, particularly those demands which occur at night when there is no generation.

Figure 45 displays the day total deficits in electrical generation in June: the *mean* day total deficits of all the individual runs (blue bars), and also the day total deficits of *an aggregation of the same 100 runs* (black bars).

Figure 45 Deficits in June (mean of individual runs, and aggregated runs). Rural scenario, "average" conditions

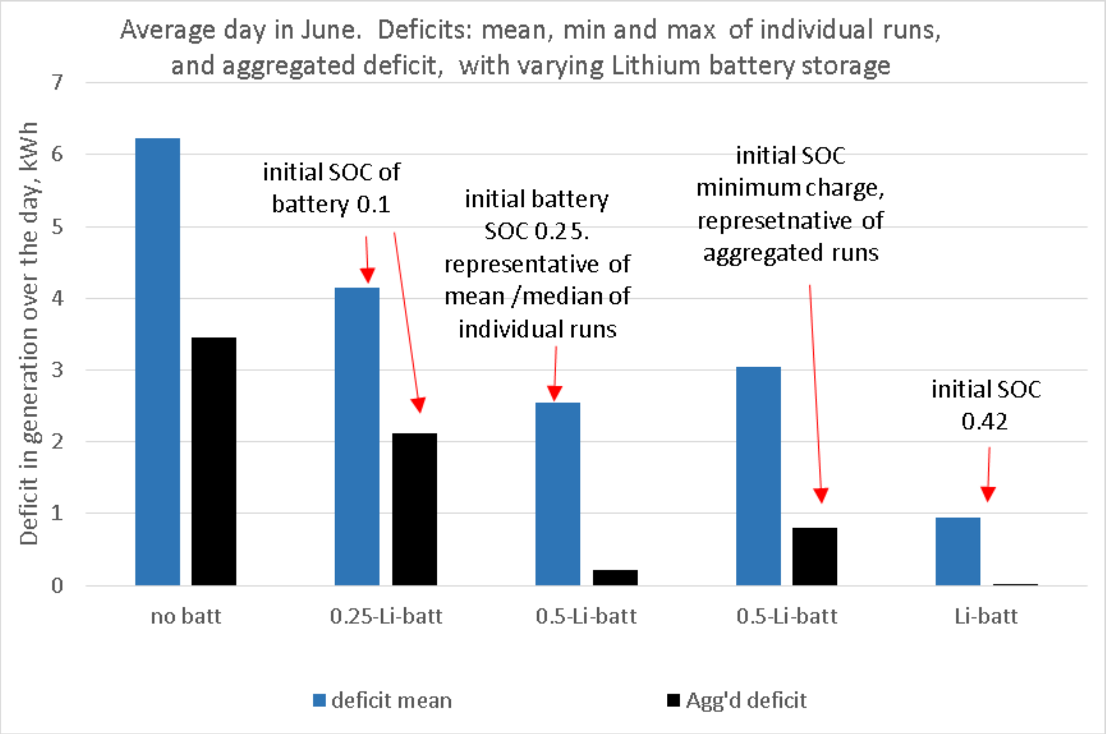


Figure 45 shows that simply aggregating 100 runs, even without storage, results in the mean day total deficit halving, and is more effective than a "minimal" (0.25) lithium battery. Installing increasing quantities of storage gives continuing reductions in deficits. With aggregation *and* a minimum battery, on a day with "average" conditions, the mean day total deficit is reduced from 6kWh to 2kWh; with aggregation and a half battery, deficit is almost eliminated. A similar pattern was also seen on clear and cloudy days, and similar results were seen for lead batteries (of quantities 1, 2 and 4 respectively).

<u>Winter</u>

Even in winter, modest excesses in generation were noted in some runs, with a mean of around 3kWh for the day, for both "Rural 1" (some storage heating) and "Rural 2" (no storage heating). Aggregation, even without storage, was effective in reducing these to less than 1kWh, and aggregation with a minimal battery eliminated excesses altogether. Storage alone did also reduce deficits, though a full lithium battery (or lead equivalent) was needed to reduce the mean excess to near zero. These are depicted in Appendix 18.

Deficits in electrical generation are described separately for “Rural 1” and “Rural 2” scenarios.

Rural 1 scenario

There are considerable deficits in electrical generation. Figure 46 displays day total deficits: the *mean* of the 100 runs (medium blue), the *minimum* value of the 100 (lighter blue), the *maximum* value out of the hundred (dark blue), and the day total deficit of *an aggregation of the same 100 runs* (black). The chart shows the huge range in electrical deficits between runs, from under 5kWh to approaching 100kWh.

Figure 46 Rural 1 scenario, January. Mean, min, and max deficits of individual houses, and deficit of aggregation of houses, with varying lithium battery storage.

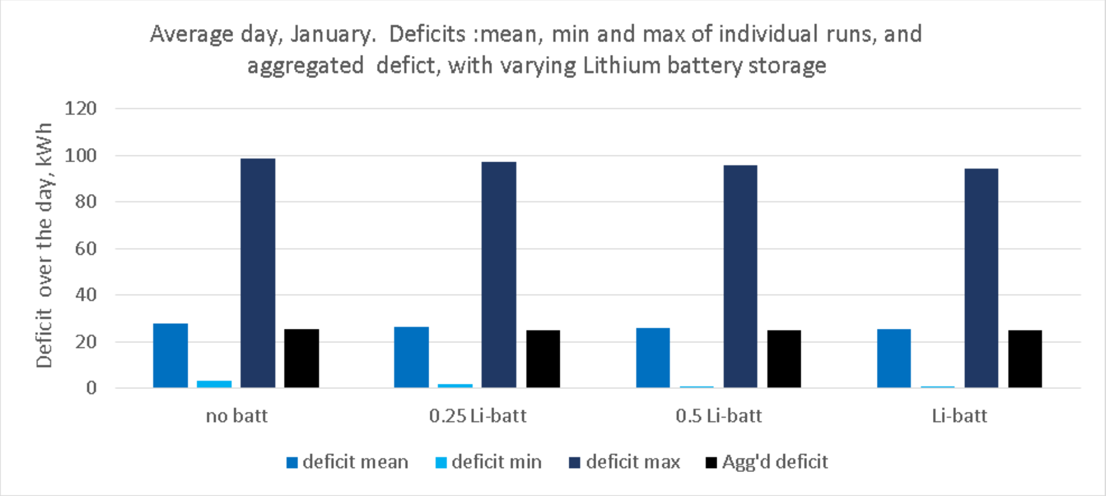
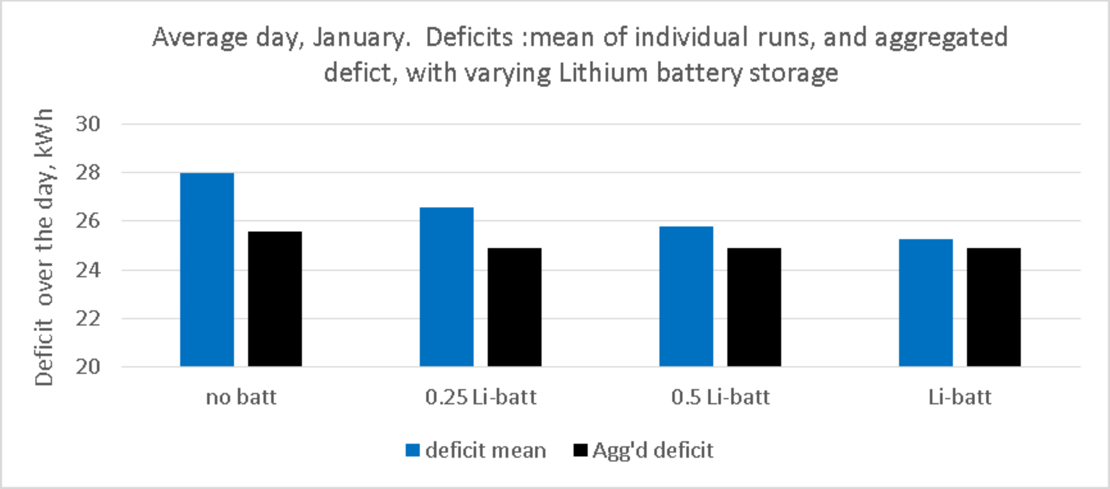


Figure 47 displays the same data as Figure 46, but excludes the minimum and maximum of the day total deficits, for clarity of viewing. Both charts show that on an average day, mean deficits are well over 20 kWh. Installing storage, individually, has limited benefit, up to 2.7kWh for a full lithium battery. Aggregation, even without storage, reduces deficits by 2.4kWh; adding minimum storage (0.25 battery) to an aggregation of runs bring very limited benefit (0.7kWh reduction in deficit); there is no benefit at all in further increasing storage. The effect of storage is even less pronounced on cloudy days, and slightly increased on clear days, as shown in Appendix 18. (All runs assumed the battery held the minimum charge at the beginning of each run. This is a reasonable assumption for most cases, though it may very slightly overestimate deficits after a clear day, for runs with very little demand.)

Figure 47 Deficits in generation: Rural 1 scenario, January, with varying lithium battery storage

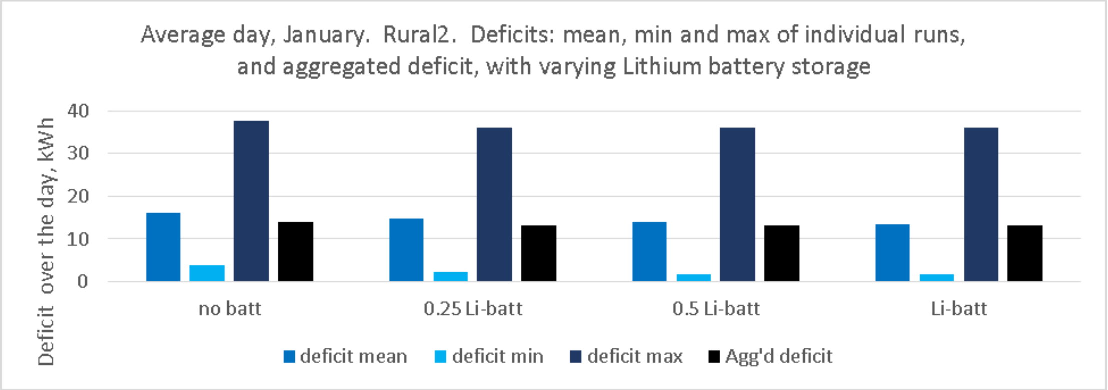


It was also noted that the *median* deficit (not displayed) was considerably lower than both mean and aggregate deficit. This is because of a skewed distribution of demands: 20% of runs had storage heating, and so very much higher demand, than the majority of others.

Rural 2 scenario (as for Rural 1, but no storage heating)

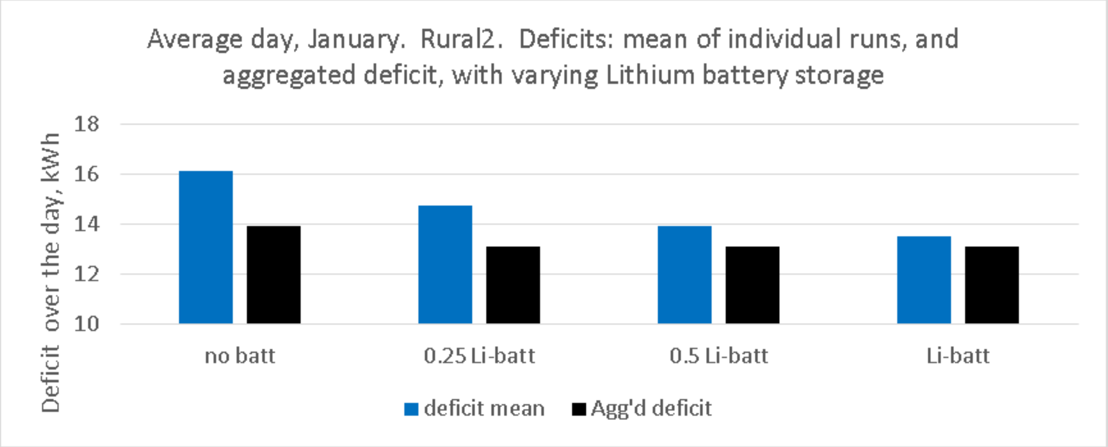
There are still considerable deficits in generation, but considerably smaller, and with a much reduced range in values, compared to “Rural 1”, as shown in Figure 48.

Figure 48 Rural 2 scenario, January. Mean, min, and max deficits of individual houses, and deficit of aggregation of houses, with varying lithium battery storage.



Again, adding storage reduced deficits by a small amount: aggregation alone was as effective as a 0.5kWh battery, and aggregating with a 0.25 kWh battery brought the maximum reduction in deficit; there was no benefit in further increasing battery capacity, as shown in Figure 49 (with further examples in Appendix 18). Installing lead acid battery storage had similar results.

Figure 49 Deficits in generation: Rural 2 scenario, January, with varying lithium battery storage



6.4. The effect of conditions the preceding day: State of Charge of battery at beginning of the run

In modelling, one important variable is the initial state of charge of the battery. This can be evaluated by performing a similar run over the day, and checking the state of charge at the end of the night. It was found that the batteries generally went through a daily cycle, so the final state of charge barely varied with initial state of charge.
In some cases, there is little variation between runs. For example, in winter in most conditions, most of the runs have minimum or near minimum charge by the end of the night. This is also the case for "minimal" sized batteries. However, in sunnier conditions, with larger sizes of batteries, there could be significant charge in the battery at the end of the night: in such cases there was often a wide range of results, with higher-demand runs having minimal charge, and runs with lighter demands having a high state of charge.

The two charts below show a comparison of a summer simulation, urban scenario, with two different cases: in the first case (Figure 50) the initial state of charge is representative of the mean / median charge in batteries following an "average" or "clear" June day. (Initial SOC was taken as 0.26 for individual runs, and 0.21 for aggregated runs with a half lithium battery; an initial SOC of 0.5 was used, for both individual and aggregated runs with a full lithium battery.) In the second case (Figure 51), the initial SOC was representative of cloudy conditions the previous day (in this case an initial minimum SOC was taken for both battery sizes, individual and aggregated runs.)

Figure 50 Effect of Li battery storage on deficits: urban scenario, June, an "average" day after an "average" or clear day

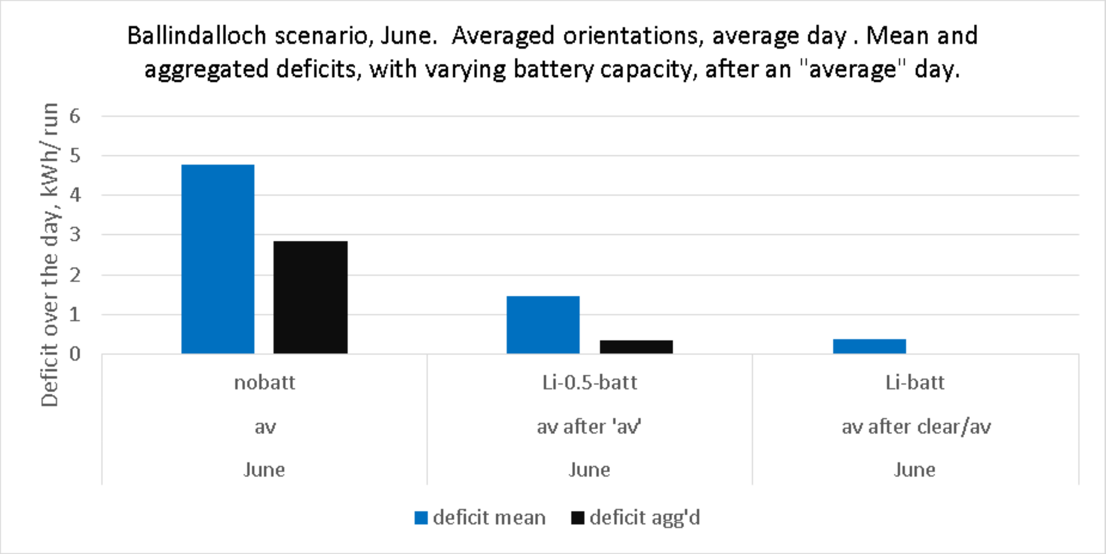
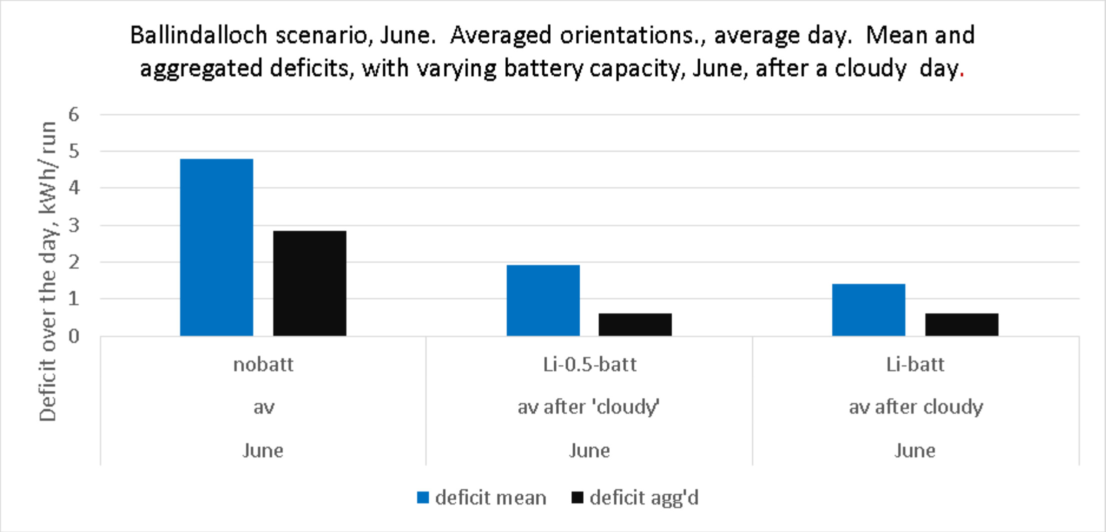


Figure 51 Effect of Li battery storage on deficits, urban, June, an "average" day after a "cloudy" day



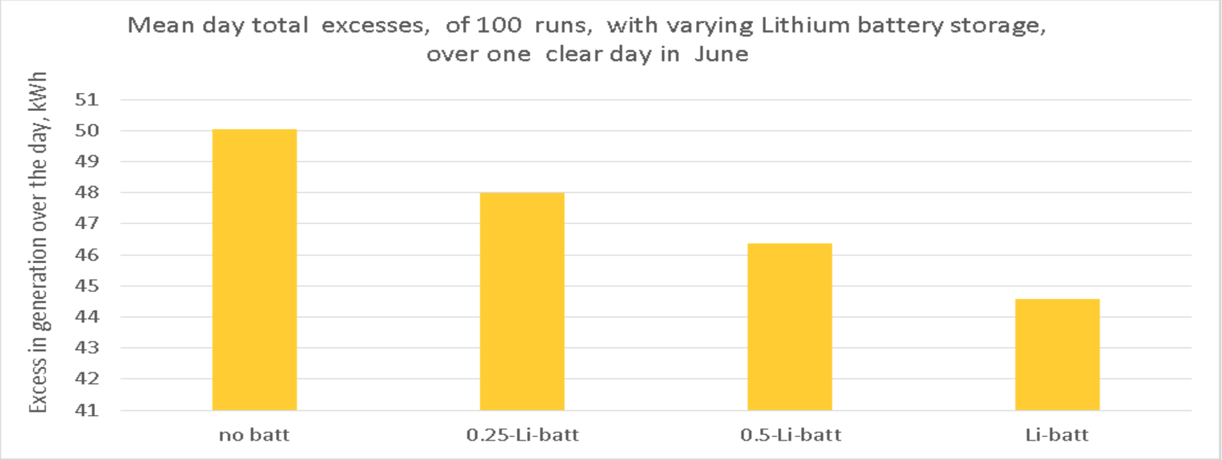
As can be seen, with cloudy conditions the preceding day, mean day total deficit is approximately 0.5kWh higher (with half a lithium battery storage), and approximately 1kWh higher (with a whole lithium battery) than when the preceding day is average or clear. Differences of similar magnitude were found for rural scenario, displayed in

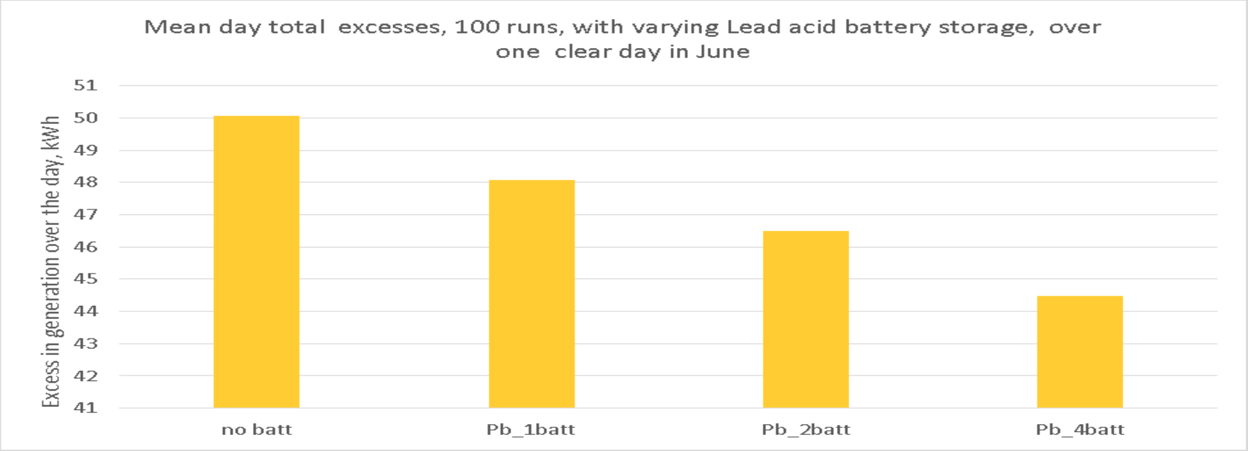
Figure 45. Other simulations (for example, displayed in Appendix 18) found similar results: the differences in mean day total deficits, and aggregated day total deficits, caused by different weather conditions the preceding day, was around 1kWh.

6.5. Comparing different storage systems: lithium and lead batteries

For both urban and rural scenarios, the effect of adding storage, either lead or lithium, were modelled separately. Figure 52 shows the effect both lithium and lead acid batteries have on the mean day total excesses, on a clear day in June, rural scenario. Figure 53 shows the same, but the effect of the different storage on mean day total deficits. In both cases, the SOC of the battery was taken as representative of a preceding "average" weather day.

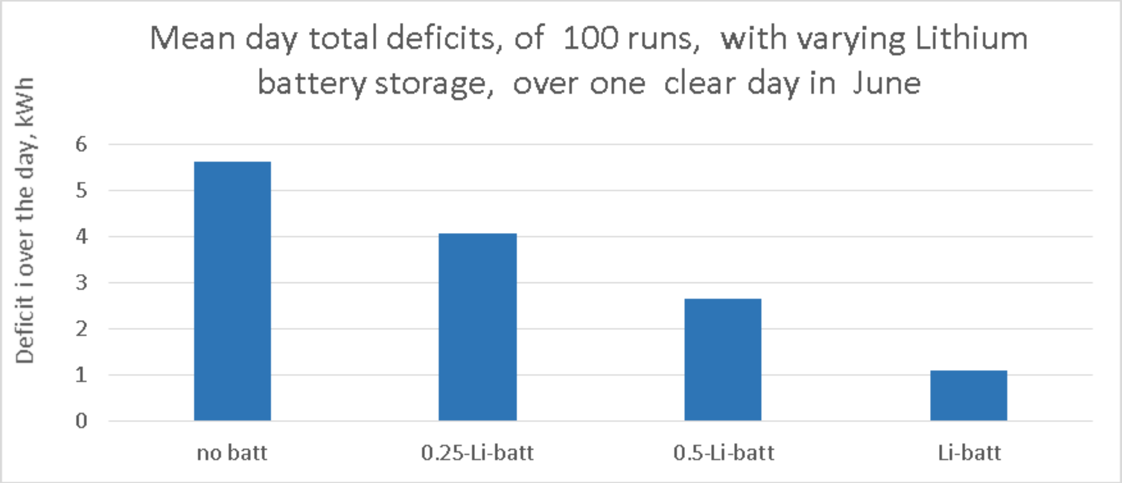
Figure 52 Effect of lithium and lead battery storage on mean day total excesses, clear day in June. Rural scenario

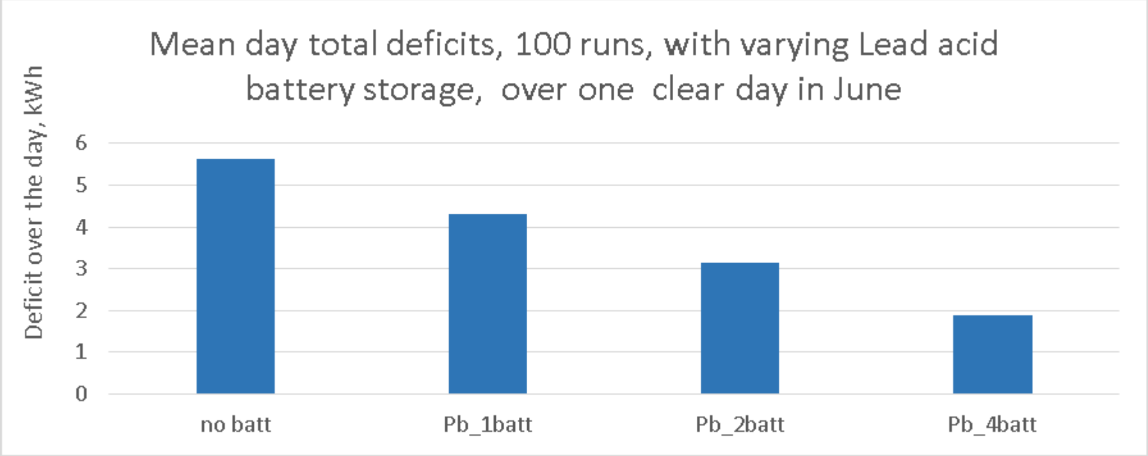




In both cases, the effect of adding one lead battery is very close to that of one-quarter lithium battery; this applies to both excesses and deficits, and to multiples of these batteries. The same effect was observed for other conditions of weather, season, and other scenarios (urban).

Figure 53 Effect of lithium and lead battery storage on mean day total deficits, clear day in June. Rural scenario.



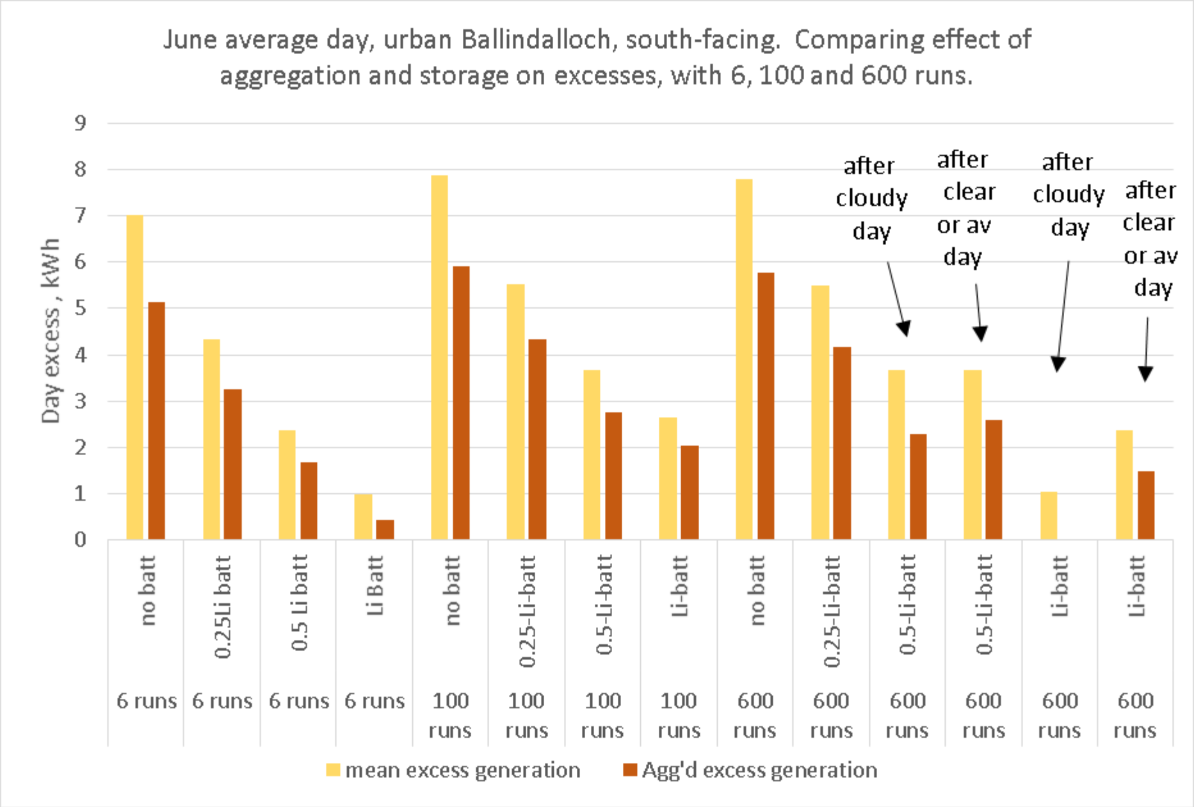


6.6. Comparing different numbers of runs: six and six hundred

The effect of aggregation and storage was investigated with aggregations of different sizes. Besides the 100 runs modelled, described above, it was decided to model an aggregation of six, which could be a tenement close. A larger aggregation was also chosen, of 600. In all cases, south facing summer day, Ballindalloch urban scenario.

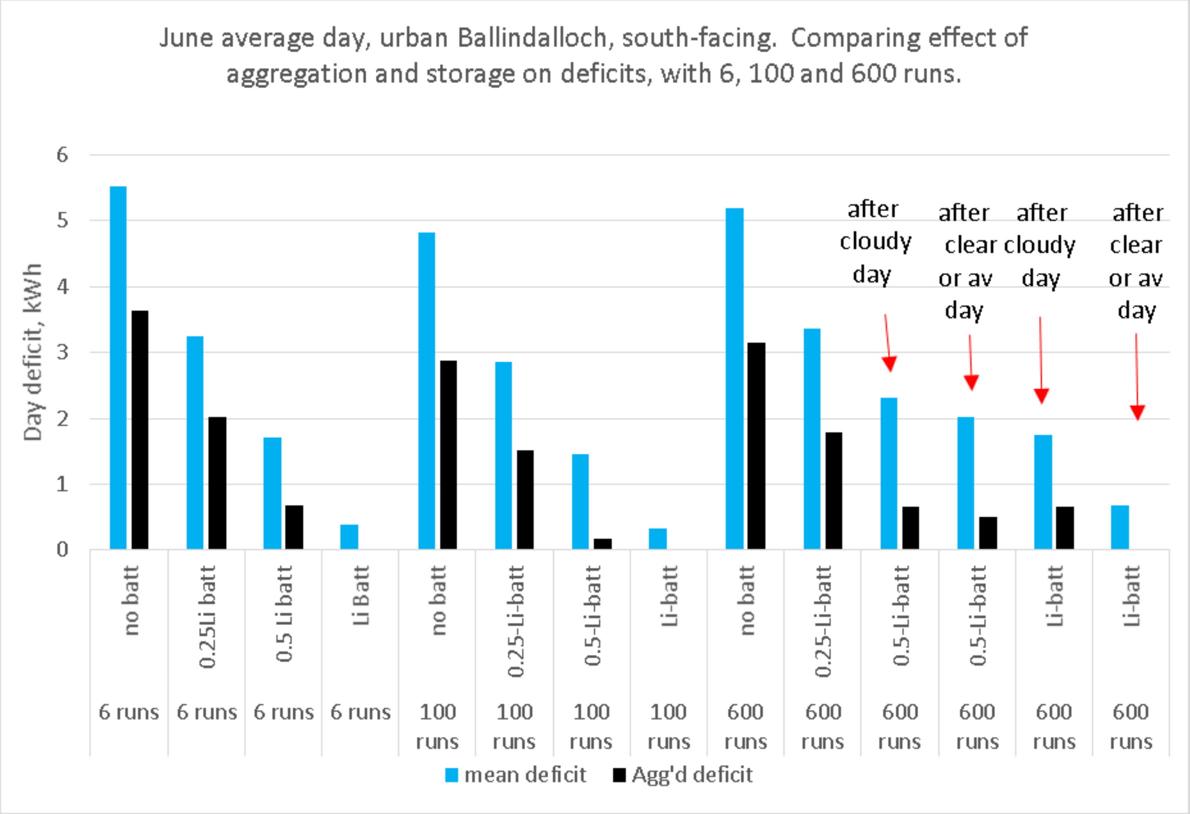
Figure 54 and Figure 55 depict excesses and deficits on an “average” June day. Both graphs show: effect of varying amount of storage *on an aggregation of six runs* (first four pair of bars), then the effect of varying quantities of storage *on an aggregation of 100 runs* (middle four pair of bars), and finally, the effect of incorporating varying quantities of storage *on an aggregation of 600 runs* (final six bars). The annotated final four pars of bars are included to show that conditions the previous day affect excesses and deficits: half-size battery, after a cloudy day; half-size battery after an average / clear day, respectively; full-size battery after a cloudy day; and a full-size battery after an average or clear day. All bars without annotations are for a preceding day of "average" weather.

Figure 54 Summer day total mean excesses, comparing aggregation and storage, with groups of 6, 100 and 600



These graphs show that aggregation and storage, both separately and in combination, are effective in reducing excesses and deficits. What is surprising is that the *effect* of aggregation does not change much with *size of aggregation*: an aggregation of this group of six has much of the effect as an aggregation of 100 in reducing excesses and deficits; aggregations of 600 are barely any more effective than of 100. (On cloudy days, the benefits of larger aggregations are more pronounced, but aggregations of six runs still achieve well over 50% of the benefits in excess and deficit reduction, as aggregations of 100, as shown in Appendix 19.)

Figure 55 Summer day total mean deficits, comparing aggregation and storage, with groups of 6, 100 and 600



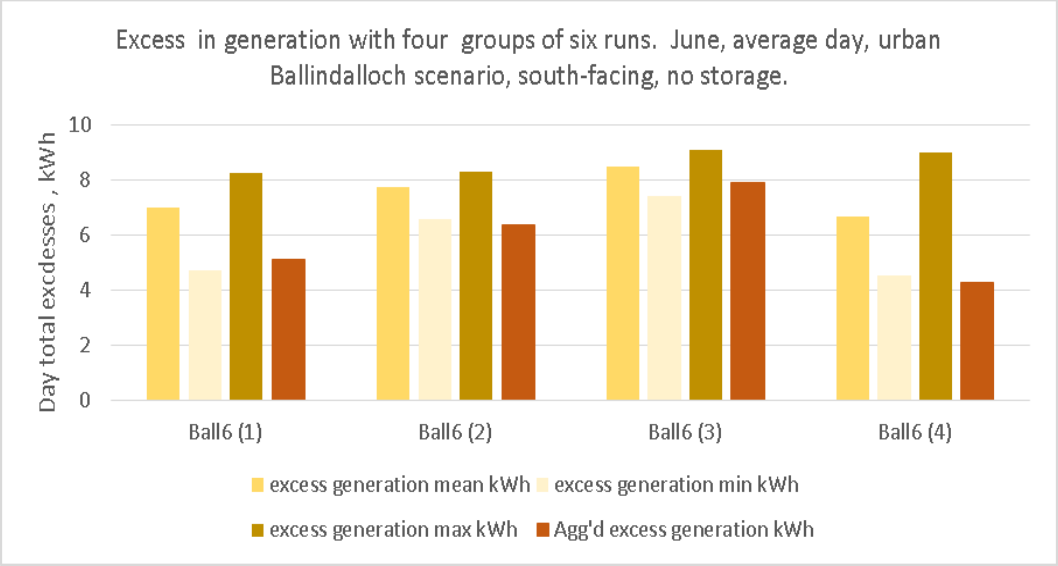
Further examination of groups of six runs

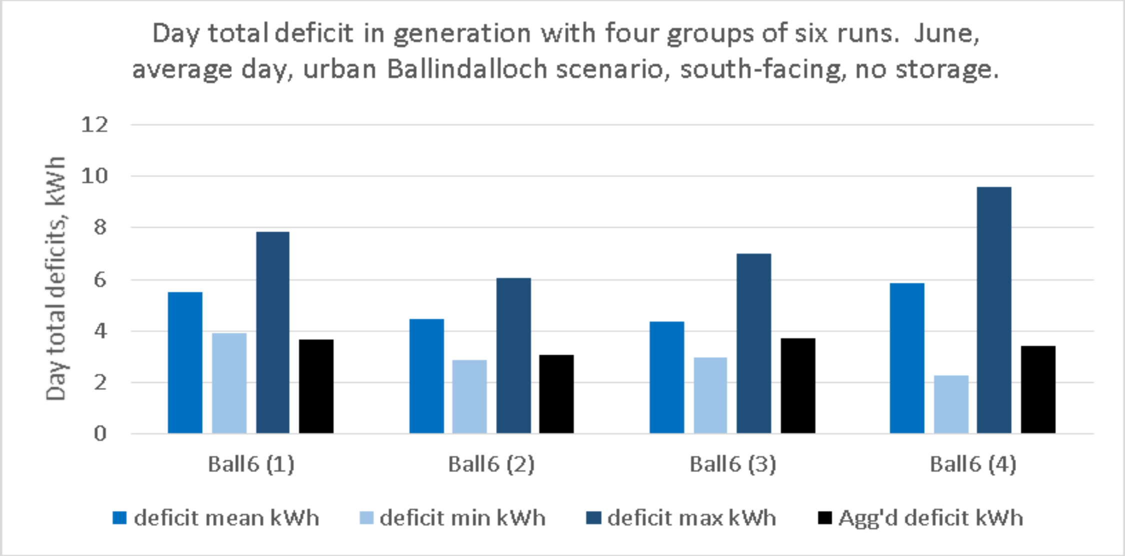
It was wondered if the group of six represented above (in Figure 54 and Figure 55) was “typical” of other groups of six.

Thus, four such groups of six runs were also studied (whose demand profiles are shown in Figure 34). The day total excesses and deficits in generation between these four groups are displayed in Figure 56.

It was found that indeed, there was variation, between the four groups, in the degree to which aggregation reduced excesses and deficits in generation.

Figure 56 Excesses and deficits in generation: comparing four groups of six flats, urban Ballindalloch scenario, June, no storage





The difference between the mean excess / deficit (first bar in a group: mid yellow / mid blue) and excess / deficit for an aggregation of runs (last bar in group, coloured orange / black) ranges from 0.6kWh to 2.4kWh for the day. Close number 1, used in the comparison with larger groups of runs in Figure 54 and

Figure 55, had a deficit / excess saving of 1.8kWh, a little higher than the average of these four groups (1.6kWh).

This preliminary investigation shows close number one, shown in Figure 54 and Figure 55, is

- within range of the four groups of six inspected, and
- brings reductions in deficits and excesses a little higher than the average across these four groups of six.

A study of a larger number of groups of six would be needed to determine more accurately the “average” saving by a group of six. However, the variation was not huge, and this approach is considered acceptable as a first approximation.

6.7. Comparison of different temporal resolutions

For the urban Ballindalloch scenario, 100 demand profiles, for June, were compared: in their original 1-minute resolution, and the same datasets smoothed to 5 minute and one hour resolution, as displayed in Section 5.6.

For the same runs, power generation and demand, and excesses and deficits in generation were calcuated, for a June, south-facing, urban Ballindalloch scenario, for the same three temporal resolutions. Results for clear, cloudy and average days are shown separately. Figure 57 displays maximum power generation and demand (individual and aggregated, per house).

Figure 57 Maximum power generation, maximum demand from individual houses, and maximum aggregated demand per house, over 100 runs, calculated from data with three temporal resolutions.

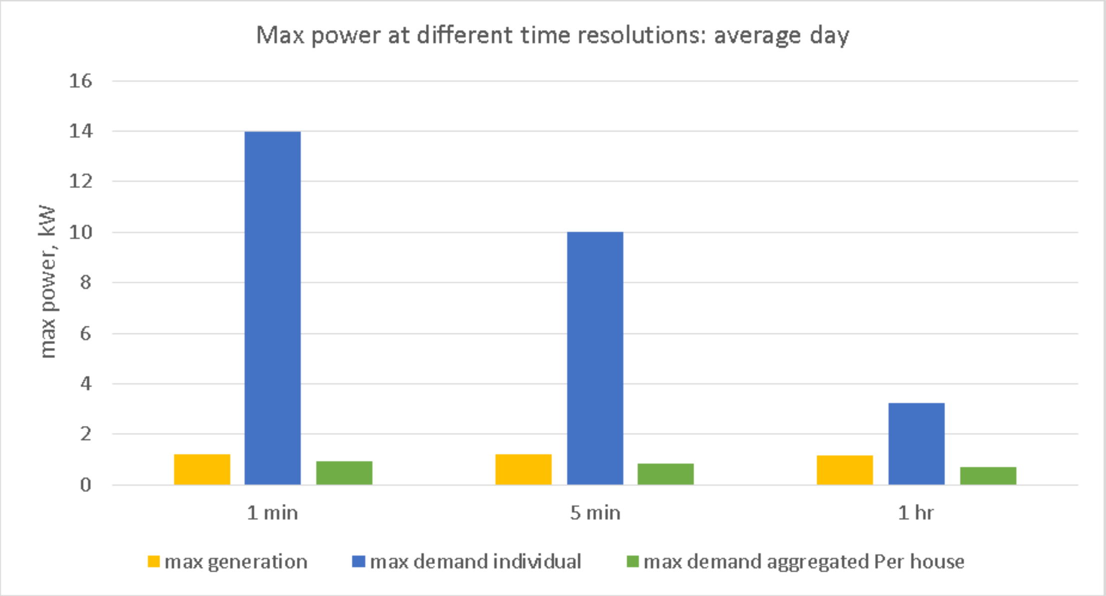
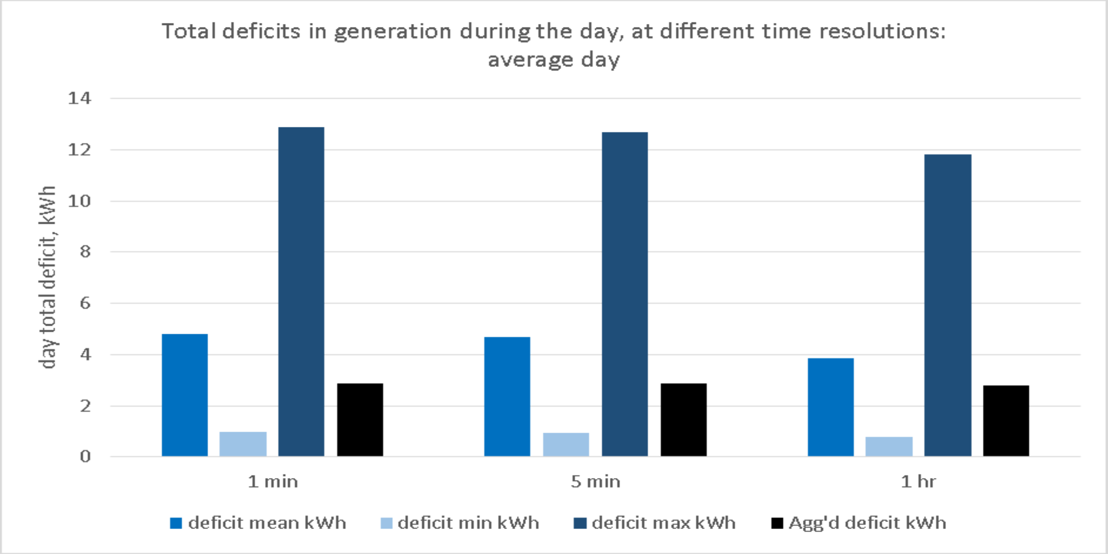


Figure 58 displays day total deficits in electrical generation: mean, minimum, and maximum, and also the total deficit from an aggregation of all the runs. The graphs are for an "average" June day. Similar graphs, for cloudy and clear conditions, and displaying day total excesses in generation, are displayed in Appendix 20.

Figure 58 Day total deficits in electrical generation over 100 runs: mean, minimum, and maximum of individual runs, and deficit of aggregated runs. Calculated from data with three temporal resolutions.

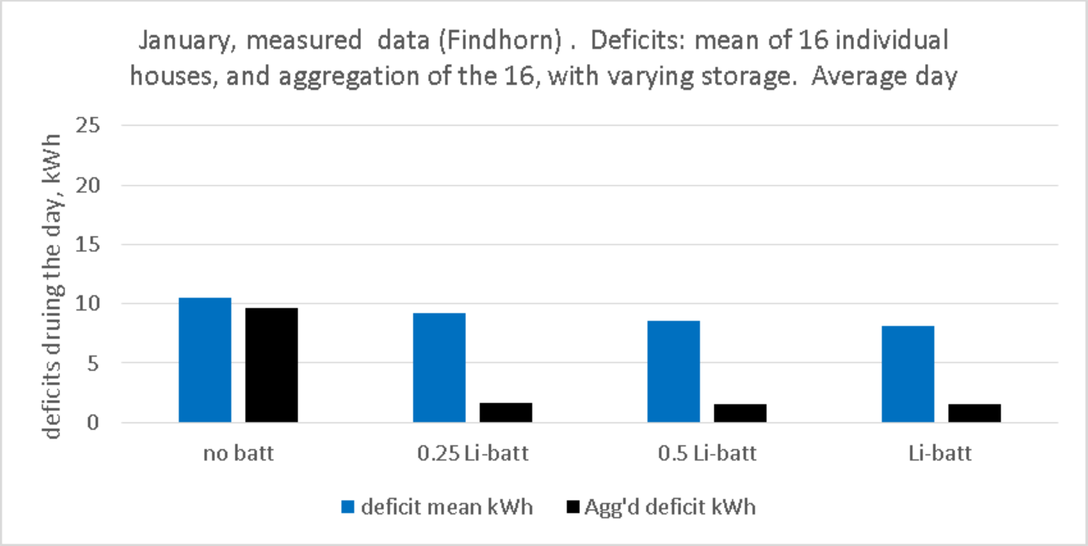


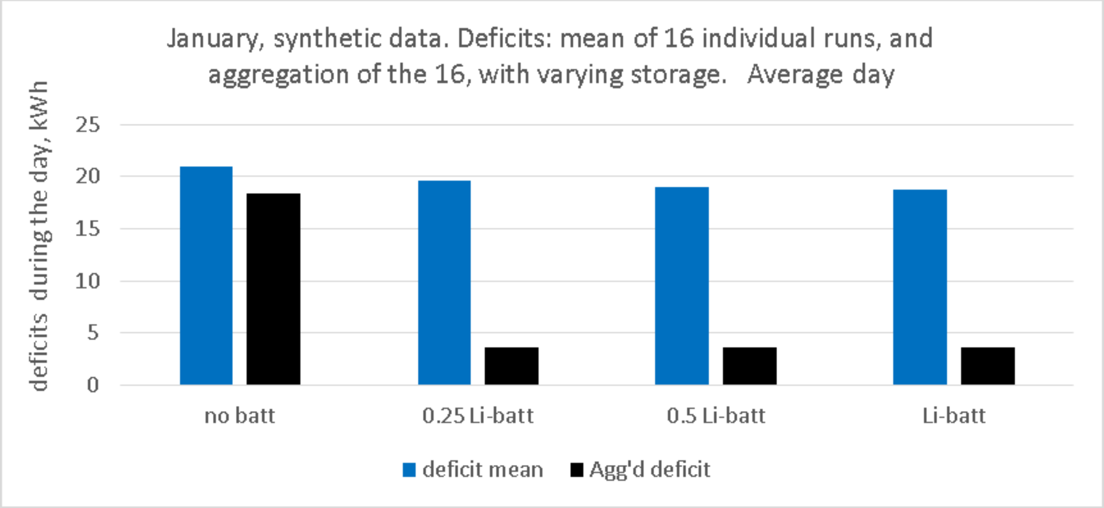
6.8. Case study: comparison with measured data from Findhorn

The individual demand profiles, for both the case study (measured data) and comparison (synthetic data), are displayed in Figure 39 (summer) and Figure 40 (winter)

These demand profiles were processed, assuming "rural" PV generation, with Glasgow solar radiation. A sample of results, day total deficits in generation, with varying amounts of storage, are shown, comparing results obtained from measured and synthetic demand data. Figure 59 shows deficits in winter, and Figure 60 shows deficits in summer, both for an "average" day. Excesses in generation are shown in Appendix 21. In winter, both the measured Findhorn houses, and the control group of synthetic data, had deficits in electrical generation, which were only slightly reduced by installation of storage, of any quantity, on an individual basis. In both cases, aggregation alone slightly reduced deficits. However, aggregation, in conjunction with minimal storage, substantially reduced the day total deficits. There was no further benefit from further increasing the quantity of storage. Despite the difference in size of deficits between the measured and control group, the same pattern was seen.

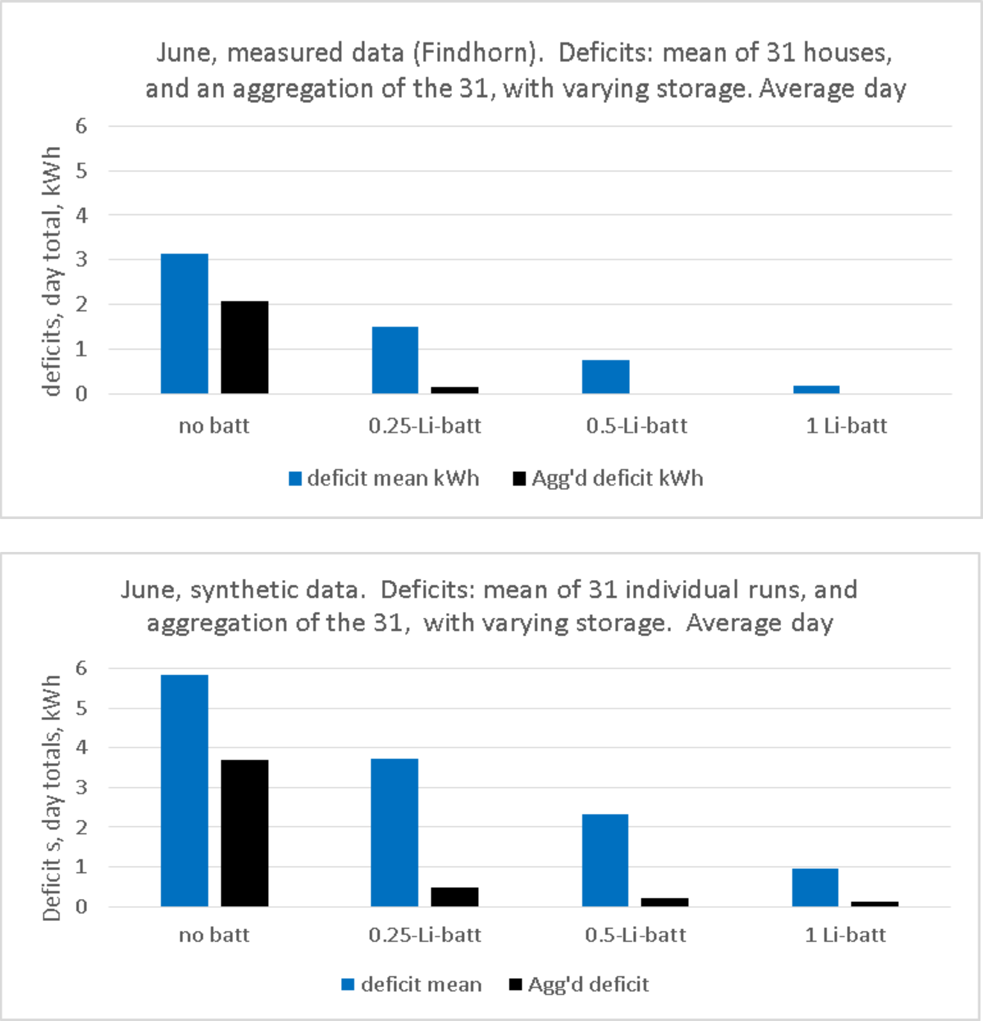
Figure 59 Winter deficits in generation, calculated from measured (Findhorn) and synthetic demand data. Day total deficits: mean, and aggregation of 31 houses, average day, with varying storage.





In summer, the pattern was slightly different. Deficits were smaller, and installing storage on an individual basis, did reduce deficits. Increased quantity of storage, on an individual basis, led to greater deficit reduction, and large (half –full battery) were needed to substantially reduce deficits. Aggregation alone significantly reduced deficits in both cases. Aggregation together with minimal storage was effective in near-elimination of deficits. Again, further increase in quantity of storage brought little benefit. Again, the same type of pattern was seen for both measured and control group.

Figure 60 Summer deficits in generation, calculated from measured (Findhorn) and synthetic demand data. Day total deficits: mean, and aggregation of 31 houses, average day, with varying storage.



6.9. Estimation of potential benefits of aggregation and storage

A comparison is made here of various combinations of aggregation and storage. All assume a south-facing roof, urban scenario, “average” day, and that the preceding day is also “average”.

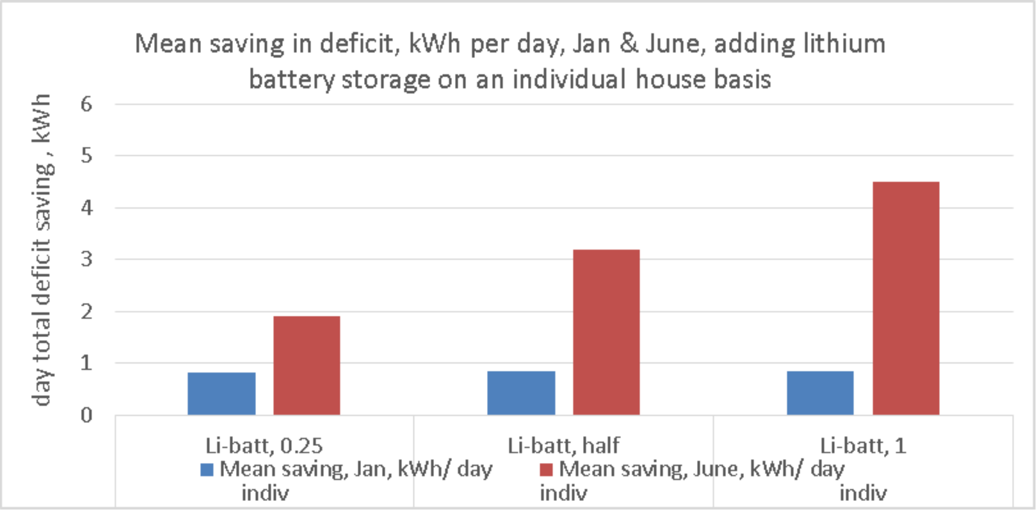
Urban scenario: reductions in mean day total deficits, kWh, January and June

This section describes the effect of adding various combinations of storage, and aggregation, on mean day total deficit, for a winter day (shown in blue) and a summer day (shown in red).

Incorporation of storage, on an individual basis

Mean deficit reductions of around 2 - 4.5 kWh/day in summer, and around 0.7kWh/day in winter, can be achieved by installing storage, on an individual basis. The benefits in deficit reduction increase with storage capacity in summer, but not in winter, as Figure 61 shows.

Figure 61 Mean day total deficit saving, achieved by installing varying storage on an individual household basis, urban scenario

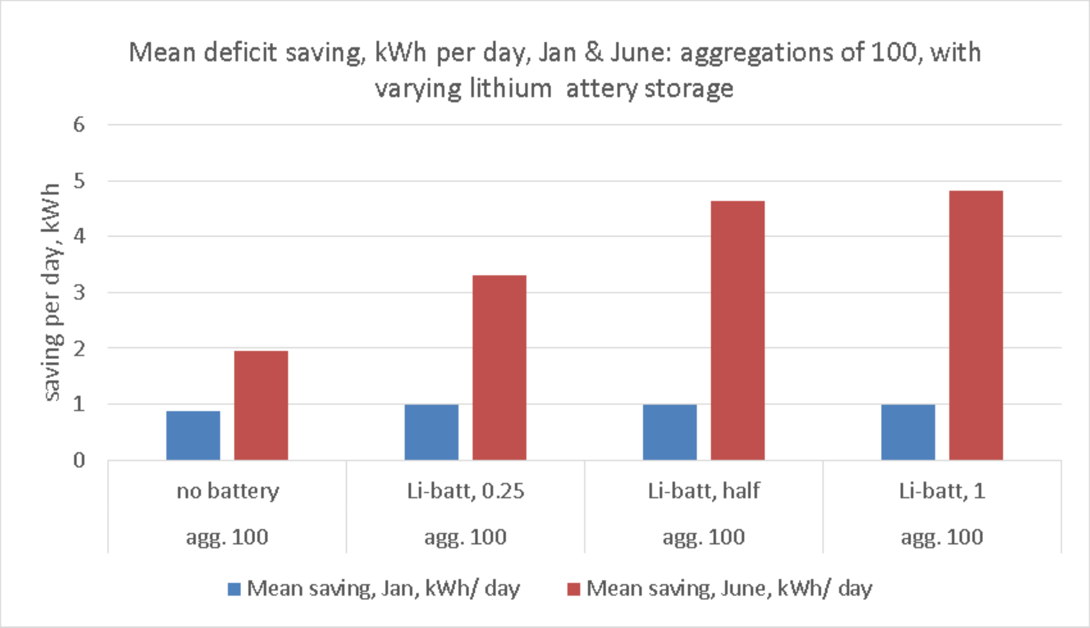


Incorporation of 1, 2 and 4 lead batteries, caused very similar results as one-quarter, on-half and one full lithium battery, respectively.

Incorporation of storage, on an aggregation of 100 flats

Figure 62 shows that there are greater deficit savings if storage is installed on an aggregation of 100 houses, compared to installing the same storage on individual basis (described previous paragraph).

Figure 62 Mean day total deficit saving, achieved by installing varying storage (and none) in conjunction with aggregating 100 houses, urban scenario



Again, very similar results were seen with 1, 2 and 4 lead batteries, respectively.

The effect of size of aggregation and quantity of storage on deficits

The following two charts, together, investigate the effect on day total deficits, which aggregation of different size, in combination with different quantities of storage, cause. Figure 63 displays day total deficits where there is "no storage" and "minimal storage" in combination with aggregations of six (two different groups of six are displayed, "close no. 1", and "close no. 2", described in Section 5.5), 100, and 600.

Figure 64 shows savings in deficits that larger storage capacity (one half, and one whole lithium battery), in combination with the same 6 (close 1), 6 (close 2), 100 & 600 aggregations. (More detail is shown in Appendix 22.)

Figure 63 Mean day total deficit saving, comparing aggregations of 6 (“close no.1 and “close no.2”), 100 and 600, with no storage, and minimum storage (one-quarter lithium battery). 100 houses, urban scenario

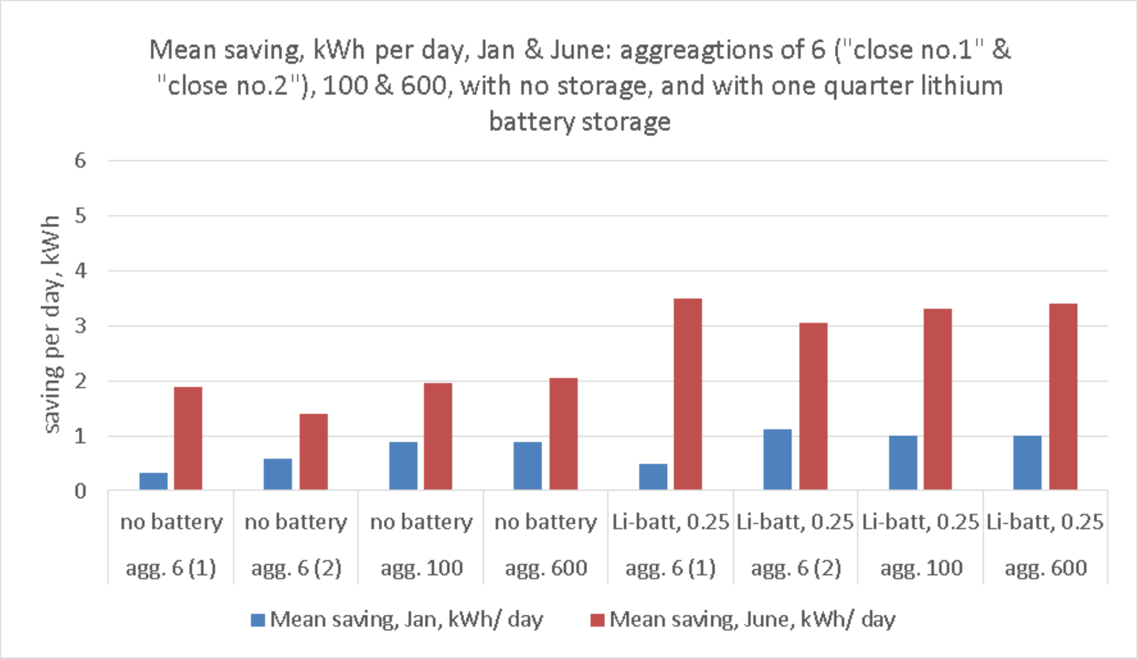
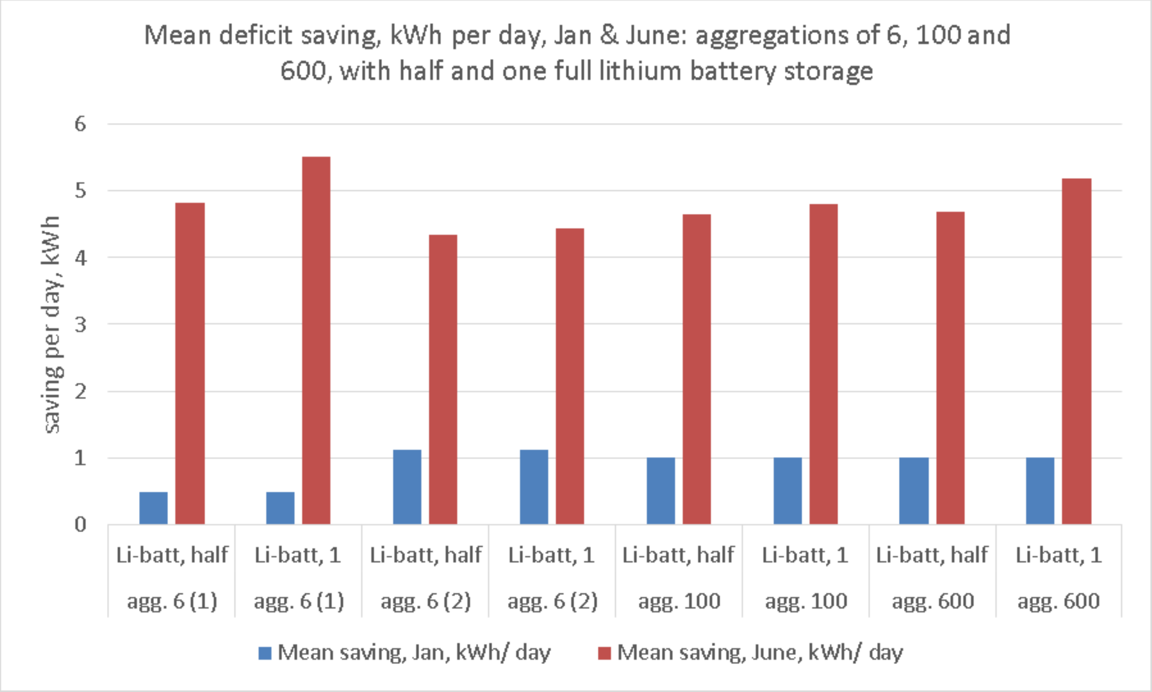


Figure 64 Mean day total deficit saving, comparing aggregations of 6 (“close no.1 and “close no.2”), 100 and 600, with no storage, and minimum storage (one-quarter lithium battery). 100 houses, urban scenario



In summary

Installing storage on an individual basis brings about benefits in deficit reduction, 2-4.5kWh per day in summer, depending on quantity of storage, and 0.7kWh in winter (regardless of quantity of storage).

Large aggregations (around 600) and maximum storage result in the greatest savings in day total deficits, up to 1kWh/day in winter, and around 4.5-5 kWh in summer. Reducing aggregation number from 600 to 100 causes little reduction in benefit; reducing quantity of storage from 1 battery to one half battery also has relatively little effect. Aggregations of 6 are very variable, but the limited study here found broadly similar results to aggregations of 100.

The greatest benefits of aggregation were seen at small battery capacities. Aggregations (of all sizes) combined with smaller storage capacity, of one-quarter battery, yielded day deficit reductions of around 3-3.5kWh in summer and around 0.5-1 kWh in winter.

Aggregating, even without storage, gave improvements, of around 1.5-2kWh/day in summer, and 0.3-0.8kWh/day in winter.

Rural scenario: reductions in mean day total deficits, kWh, January and June

Similar calculations were performed as above, based on aggregations of 100, and varying quantities of lithium and lead acid battery storage, for the “Rural 1” scenario (with storage heating), again, for an “average” day preceded by an “average” day. Combined orientations of houses were used in all calculations.

Installing storage on an individual basis, gave a mean deficit reduction of around 1.5-5kWh in summer, and 1-2.7 kWh in winter, as shown in Figure 65 (which shows effect of both lead and lithium batteries). Figure 66 shows that installing maximum storage in combination with aggregation gave deficit reductions up to 6kWh/day in summer, and 3kWh in winter. Reduction in the quantity of storage amount makes negligible difference in winter, but reduces summer savings, e.g. minimal storage and aggregation saved about 4kWh per day. Aggregating even without storage causes a measurable mean deficit reduction of around 2.5kWh/day (winter and summer).

Figure 65 Mean day total deficit saving, achieved by installing varying storage on an individual household basis, rural scenario

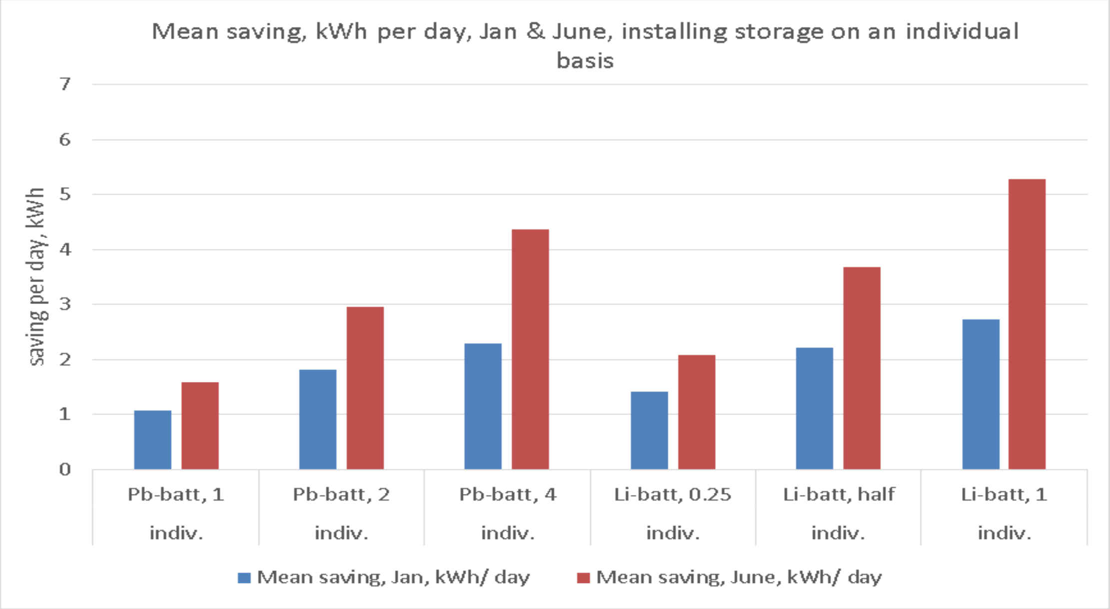
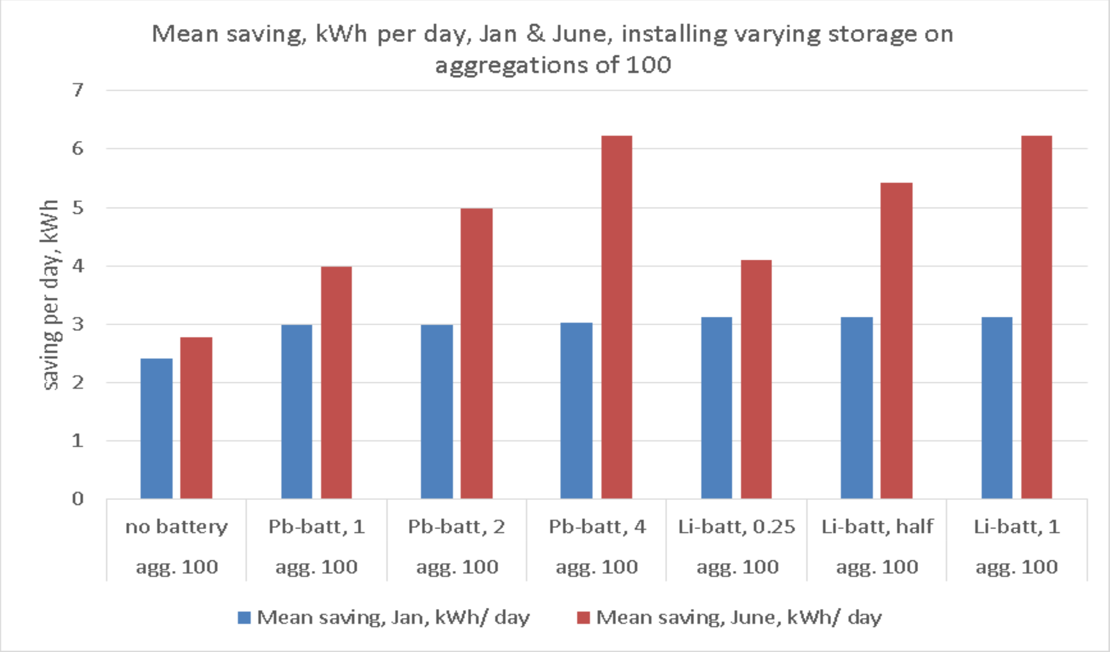


Figure 66 Mean day total deficit saving, achieved by installing varying storage (including none) on an aggregation of 100 houses. Rural scenario



The above graphs also show that the savings in deficits caused by installing storage of one lead battery was very similar to one-quarter lithium battery; this also applied to multiples of these batteries.

Estimation of potential revenues from aggregation and storage

Potential annual savings in purchased electricity were estimated from the day total deficit savings, estimating 50% of the year to be as in January, and 50% as in June. Clearly, this can give only an approximation, but gives an indication of scale. This is based on reduction in purchased quantity of electricity only. These estimated savings, in kWh/year, are shown in Appendix 23. From these estimates of annual electricity savings, potential annual revenues were calculated (i.e. reductions in household electricity bills), based on different scenarios of electricity tariff.

Flat rate tariffs

A selection of results are presented below.

Urban scenario

For the urban scenario, with two flat rate tariffs: a present scenario of 15p/kWh and a future scenario of 30p/kWh (shown in orange).

The estimated annual electricity consumption, taking into account PV generation, but *without any storage or aggregation*, is 2540 kWh. Thus, for the two tariff scenarios, the estimated annual bill, with no storage or aggregation, is:-

Scenario 1 annual bill - £381 ***Scenario 2 annual bill - £762.***

Potential savings in annual bill are shown: in blue, for present scenario, and orange for the future tariff scenario. Figure 67 shows potential annual revenue from installing storage on an individual basis, and Figure 68 shows the potential annual revenue from aggregation and storage in the same urban scenario.

Aggregations of 6 (not displayed) were variable but similar to 100, aggregations of 600 (also not displayed) gave potential savings of £0-10/yr (15p/kWh tariff) compared to aggregations of 100.

Figure 67 Potential revenue savings by installing storage on an individual household basis. Urban scenario, flat-rate electricity tariffs

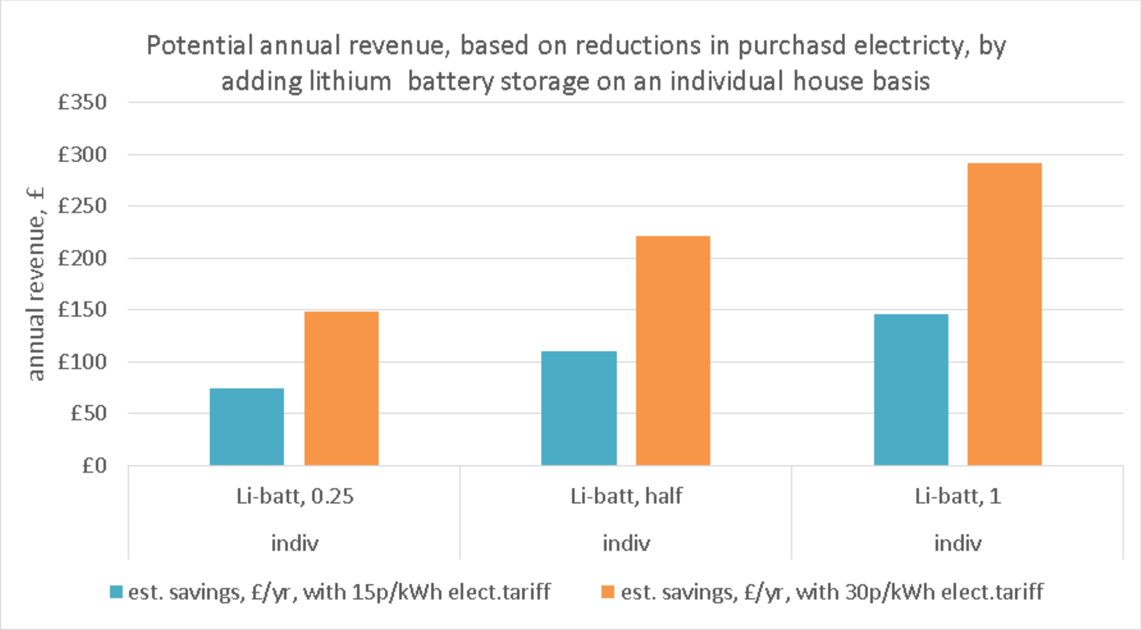
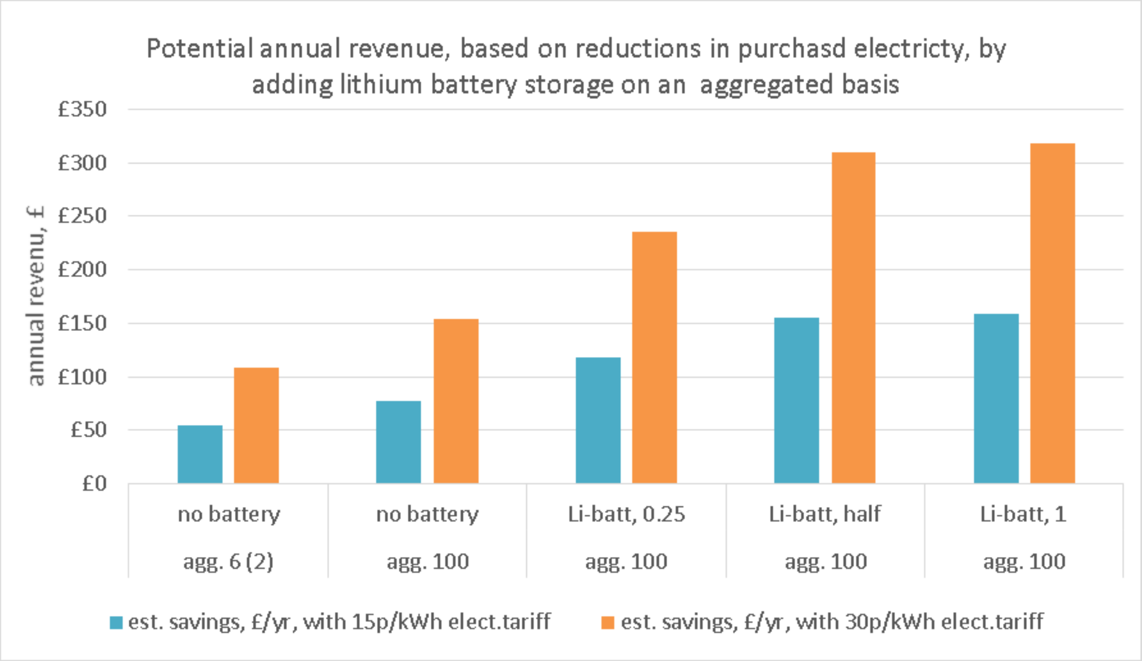


Figure 68 Potential revenue savings by installing storage and aggregation. Urban scenario, flat-rate electricity tariffs



Rural scenario

In the rural scenario, annual electricity consumption is much higher because of substantial heating demands. The estimated annual electricity use, with solar PV, but no storage or aggregation, is 6250kWh. For the two electricity tariff scenarios, estimated bills are:

Scenario 1 annual bill - £937 ***Scenario 2 annual bill - £1874.***

The potential revenues (reductions in annual bill) in the rural scenario are presented in Appendix 24. A similar pattern was seen to the urban scenario, though savings were greater. Installing storage on an individual basis caused savings to annual electricity bill of £100-220 per year with scenario 1 (depending on quantity of storage installed), and double that for scenario 2.

Installing storage in combination with aggregation led to bill savings of £200-260 for scenario 1 (and double for scenario 2). Aggregation without storage brought about annual savings of £140 for scenario 1.

Time of use tariffs *(urban scenario only)*

For the urban Ballindalloch scenario, the effect of variable time of use (TOU) tariffs was also investigated, as described in Section 4.10, Table 11. The only difference between the two tariffs is the peak tariff, from 6pm-8pm, is higher in scenario 2. (Scenario 1: 8p/15p/30p/15p per kWh; scenario 2 price 8p/15p/£1/15p per kWh)

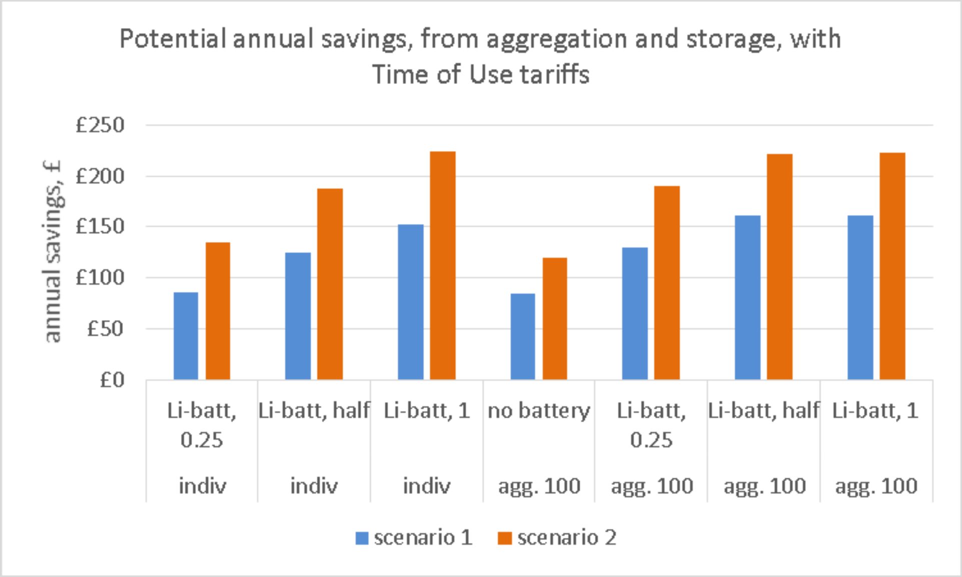
With these tariffs, the total annual electricity bill, with PV generation, but without storage or aggregation, is estimated to be:-

Scenario 1 - £419 ***Scenario 2 - £690***

The results of estimated annual savings with TOU scenario 1 and 2 are displayed in Figure 69.

The estimated total annual electricity costs are displayed in Appendix 25.

Figure 69 Potential annual savings from aggregation and storage, with variable Time of Use electricity tariffs



<u>Time of Use tariffs, and the possibility to sell to the grid.</u>

Further scenarios were considered, in which, at peak times only, electricity could be sold to the grid, at a price slightly below the peak purchase price. Scenario 1, includes the option to sell to the grid at 25p/kWh during the evening peak; Scenario 2 is more futuristic, with the ability to sell to the grid for 80p/kWh during the evening peak. Details of this scenario are displayed in Table 12.

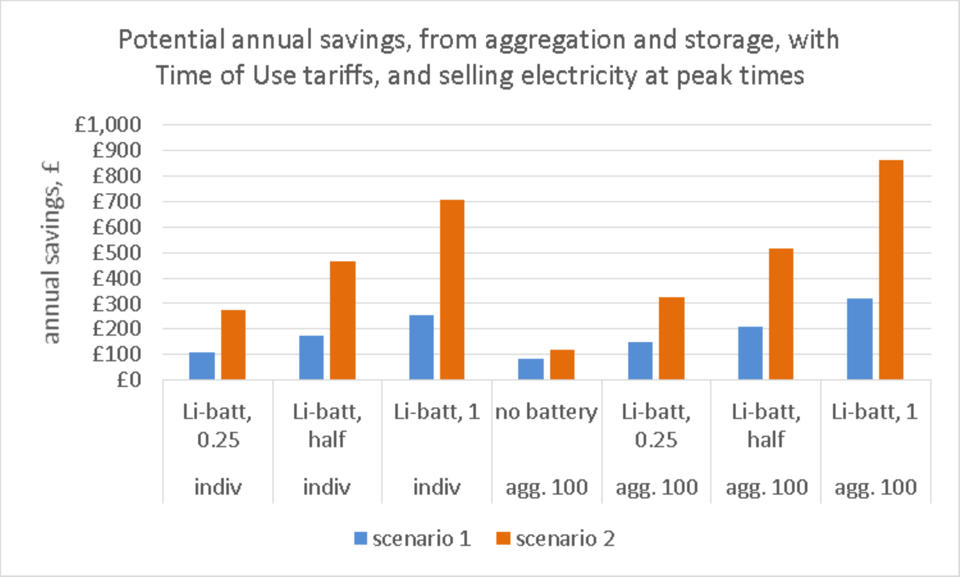
The annual electricity bill, with PV but in the absence of storage, aggregation, or any sales of electricity, are as above:

Scenario 1 - £419 ***Scenario 2 - £690***

The estimated potential savings are displayed in Figure 70.

The estimated total annual electricity costs are displayed in Appendix 25.

Figure 70 Potential annual savings from aggregation and storage, with variable Time of Use electricity tariffs, and the ability to sell electricity to the grid at peak times



In scenario 1, the maximum savings approach 70% of the annual electricity bill. Scenario 2 has a negative electricity bill for the highest storage cases.

6.10. Estimation of potential costs of installing storage

A detailed calculation of costs of installing storage is beyond the scope of this project. However, some information, from different sources, is included. Table 16 gives advertised costs of some commercially available lithium and lead batteries, suitable for domestic use. One UK installer of battery systems quotes £4,250 - £4,600 for provision and installation of a Tesla Powerwall [80].

Table 17 shows costs of some larger scale batteries.

Table 18 shows the estimates made by the Carbon Trust and Imperial College[12] on likely costs of installing lithium battery storage.

Table 16 Estimations of the potential costs of domestic-scale batteries, from manufacturers and suppliers

Battery type	Quantity	Nominal capacity	Estimated net capacity (Table 9)	Rated power	Price [2]	Source
Lithium	*0.25*	*2kWh*	*1.5kWh*	*0.75kW*	*~ £1,500*[3]	[77]
	0.5	3.2kWh	2.9kWh	1.5kW	£1,927[4]	[73]
	1	6.4kWh	5.8kWh	3kW	£3,300[5, 6]	[73, 78]
Lead acid[7]	1	2.2kWh	1.3kWh	0.44kW	£500	[79]
	2	4.4kWh	2.6kWh	0.88kW	£1000	
	4	8.8kWh	5.3kWh	1.76kW	£2000	

One UK installer of battery systems quotes £4,250 - £4,600 for provision and installation of a Tesla Powerwall [80].[8]

Table 17 Information and costs for commercial scale lithium batteries[9] [81]

Battery name	Max PV system	Capacity	Useable capacity	Max nominal power	Price
Li-40	20kWp	40kWh	28-36kWh	13.8kW	£31,946
Li-60	20kWp	60kWh	42-54kWh	18.0kW	£43,890
Li-120	30kWp	120kWh	84-108kWh	18.0kW	£79,858

Table 18 Undiscounted costs of a two sizes of lithium battery storage system, Carbon Trust & Imperial College[12]

	0.55kW system	**2kW / 7kWh system**
Capital cost (including installation)	£961	£2449
Lifetime maintenance	£92	£235
Total lifetime costs	**£1053**	**£2684**

Further estimates of potential costs compare the size of battery selected for this project, are displayed in Table 19. This table includes estimates from the Carbon

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[2] Excluding VAT and installation

[3] Battery price not stated alone. Price only give as £3000 for a whole kit, of 2kWh battery plus a 1kW inverter (estimated around £2000). "Victron hub kit", available Wind and Sun.

[4] LG ChemLi ion LG RESU3-2EX,available Wind and Sun

[5] LG ChemLi ion LG-RESU6-4EX,available Wind and Sun

[6] Tesla Powerwall, available, Wind and Sun

[7] All figures are for the 5-hour discharge rate.

[8] Price includes VAT. Differences in price according to where there are existing dc connections in the house.

[9] Available from distributor Wind and Sun

Trust and partners (Table 18) and derived from Teng et al's estimates (as discussed in Section 3.5 and displayed in Table 3).

Table 19 Estimated cost of lithium and lead batteries of size modelled, based on Carbon Trust & Imperial College[12] and Teng et al [26]

Type & number of battery used in modelling	**Nominal capacity, kWh**	**Carbon Trust & partners**	**Teng et al**	
		Estimated lifetime cost [10]	**Estimated cost of battery in 2015** [11]	**Estimated cost of battery in 2020** [12]
0.25 Lithium	1.75	£1053	£840	£420
0.5 Lithium	3.5	-	£1680	£840
1 Lithium	7	£2684	£3360	£1680
1 lead "conventional"	2	-	£380	As in 2015
2 lead "conventional"	4	-	£760	As in 2015
4 lead "conventional"	8	-	£1520	As in 2015
1 lead "advanced"	2	-	£1260	As in 2015
2 lead "advanced"	4	-	£2520	As in 2015
4 lead "advanced"	8	-	£5040	As in 2015

The costs of inverters are not examined here, as even without any storage, these items would be necessary to convert the d.c. produced by the panels into a.c. (assuming a separate d.c. circuit is not installed). Installation of aggregation and storage may well change the circuit design and choice of components: these matters are beyond the scope of this study. A converter is also likely to be needed, to convert the output from the solar panels to a voltage suitable to feed into the batteries. Again, this is beyond the scope of this project.

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[10] Cost includes installation, retailer mark-up and lifetime maintenance

[11] Estimated purchase price of battery only, not including installation or maintenance.

[12] Estimated purchase price of battery only, not including installation or maintenance.

6.11. Information relevant to estimation of costs of aggregation

An evaluation of costs of aggregation would require a study of the system design, which is beyond the scope of this project. However, some comments are included below.

It is interesting to note that the Carbon Trust and Imperial College report [12] do not have any specific costs or savings of aggregation: it appears that costs are expected to scale linearly with size of storage, regardless of whether it is installed on an individual or aggregated basis.

Power ratings of various system components.

The maximum power flows found by the modelling are displayed below: these totals are needed to inform choice of suitable equipment for system.

Table 20 Maximum power generation and demand for various aggregations, urban and rural

Urban

	Max generation, kW	Max demand, kW
Individual	2.5	10-15
6	15	15
100	250	103
600	1500	461

Rural

	Max generation, kW	Max demand, kW	
		With no storage heating	With 20% of houses having storage heating
Individual	6.3	17	17
100	630	180	220

Note: these power ratings may underestimate peak power flows, because Richardson data, being of one-minute resolution, do not model transient flows, such as spikes in demand, lasting less than a second, when equipment is switched on. The authors themselves state other information sources are necessary

Aggregation of six

In the context of six (or eight) flats in a tenement close, installing PV panels on the roof, and storage, it is assumed that doing so on an aggregated basis would have the same capital costs as installing on an individual basis. Actual cost details would depend on system design.

Aggregations of 100, urban

Some thoughts of additional items that would be needed, and which could be dispensed with, compared with installing 100 individual systems with one aggregated system, and are displayed in Table 21.

Table 21 Equipment needed to install storage. Urban scenario, 100 flats. Comparison of 100 individual systems, with one aggregated system

Item	100 individual flats	One aggregation of 100
Inverter	100 inverters: ~10-15 kW max demand	1 inverter: ~100kW max aggregated demand, 300kW peak PV output
DC connection (from PV panels to storage / aggregation point)	100 individual connections from roof (~5-20m)	~500m dc cable to central storage / connection point[13]
AC connection (from storage / connection point to all houses)	within house only	~500m of ac cable from central storage connection point to houses (if cannot connect to grid)
Capital cost of works	Not quantified	Not quantified

Aggregations of 100, rural scenarios

A comparison was also made between equipment likely to be needed for 100 individual systems, compared with for one single aggregated system of 100 houses, this time in the rural scenario (Rural 1). This comparison is shown in Table 22.

---

[13] In the urban scenario, 6 flats, that is one single tenement close, occupies 22m of length of street (Ballindalloch scenario).

Two different arrangements were considered: a “less dispersed” scenario, where the length per house is 20m, and a “more dispersed” scenario, where the distance between each house is 50m.

Table 22 Equipment needed to install storage. Rural scenario, 100 houses. Comparison of 100 individual systems, with one aggregated system

	scenario		
	100 individual houses	**1 aggregation of 100**	**1 aggregation of 100**
item		**“rural dense”**	**“rural dispersed”**
inverter	100 individual inverters, ~15kW max	1 inverter: ~200kW max demand and 700kW max generation	1 inverter: ~200kW max demand and 700kW max generation
Dc connection (from PV panels to storage / aggregation point	within house only	~2km of d.c. connection	~5km of d.c. connection
a.c. connection	within house only	~2km of a.c. connection (if connection via grid not possible)	~5km of d.c. connection (if connection via grid not possible)
Capital cost of works	Not quantified	Not quantified	Not quantified

6.12. Comparison of estimated costs and benefits of storage and aggregation

A comparison is made of potential annual revenues from different battery systems, with and without aggregation, and an indication of their costs.

Estimated revenue is based on Section 6.9 and costs from section 6.10. As discussed in section 6.11, costs (or savings) from aggregation have not been estimated.

Table 23 display potential annual revenues and the battery component of capital cost for urban scenario, tariff 1 scenarios (current / near future). Table 24 displays potential revenues and costs for Rural 1 scenario, again, with tariff 1 scenario. The same comparisons, but with tariff 2 scenarios, are displayed in Appendix 26.

Table 23 Comparison of potential revenue and costs of storage systems: urban scenario, tariff 1 scenarios: flat rate, TOU and TOU with sale to grid

Battery no. & type	Individual / aggregated	Estimated annual revenue, £			Battery cost				Total cost
					Lead battery	Li battery			Li battery
		Flat rate tariff, scenario 1 (15p /kWh)	TOU tariff scenario 1	TOU & sell to grid, scenario 1	from industry (Table 16)	from industry (Table 16)	Teng 2015	*Teng 2020*	Carbon Trust (Table 19)
0.25 Li or 1 Pb	Indiv.	£70	£90	£110	£500	~£1500	£840	*£420*	£1053
0.5 Li or 2 Pb	Indiv.	£110	£130	£180	£1000	£2000	£1680	*£840*	-
1 Li or 4 Pb	Indiv.	£150	£150	£260	£2000	£3000-£4000	£3360	*£1680*	£2684
No batt.	Agg'd 6	£50-60	-	-	£0	£0	£0	£0	-
No batt.	Agg'd 100	£80	£80	£80	£0	£0	£0	£0	-
0.25 Li or 1 Pb	Agg'd 100	£120	£130	£150	£500	~£1500	£840	*£420*	£1053
0.5 Li or 2 Pb	Agg'd 100	£160	£160	£210	£1000	£2000	£1680	*£840*	-
1 Li or 4 Pb	Agg'd 100	£160	£160	£320	£2000	£3000-£4000	£3360	*£1680*	£2684

Table 24 Comparison of potential revenue and costs of storage systems: Rural 1 scenario, tariff 1 (flat rate)

Battery no. & type	Individual / aggregated	Est. annual revenue	Estimated capital cost, £ (battery purchase only)				Est total cost
			Lead battery	Lithium battery			Li
		Flat rate tariff, scenario 1 (15p /kWh)	Battery cost, from industry (Table 16)	Battery cost, from industry (Table 16)	Battery cost, Teng, 2015	*Battery cost, Teng, 2020*	Carbon Trust (Table 19)
0.25 Li or 1 Pb batt	Indiv.	£100	£500	~£1500	£840	*£420*	£1053
0.5 Li batt	Indiv.	£160	£1000	£2000	£1680	*£840*	-
1 Li batt	Indiv.	£220	£2000	£3000-£4000	£3360	*£1680*	£2684
No battery	Agg'd 100	£140	£0	£0	£0	£0	-
0.25 Li batt	Agg'd 100	£200	£500	~£1500	£840	*£420*	£1053
0.5 Li batt	Agg'd 100	£230	£1000	£2000	£1680	*£840*	-
1 Li batt	Agg'd 100	£260	£2000	£3000-£4000	£3360	*£1680*	£2684

7. Discussion of preliminary results

7.1. Applicability of climate data used

How well do PVGIS data agree with those in the Merit database?

As displayed in Section 5.3, PVGIS data for midday diffuse insolation, agree reasonably well with those in Merit for 1972. Clear sky PVGIS and Merit values agree well for summer and mid-season, though in winter, PVGIS notes lower values. Considering how infrequent and short in duration many such winter sunny solar peaks are, this is a reasonable approximation.

Table 13 (in Section 5.3) shows peak values of "global" irradiation, taken to represent "average" conditions for a month, in the PVGIS system, lie much closer to "diffuse" (cloudy days) in winter, and approach mid-way between "diffuse" (cloudy) and "clear-sky" values in late spring, presumably reflecting weather conditions and the relative likelihood of clear or cloudy conditions. This correlation is broadly supported by weather data in Merit, summarised on the same table, though a study of more years of data would be needed for greater certainty.

Overall, the PVGIS values are considered to be in agreement with climate data in the Merit database.

How many months need to be studied to estimate irradiation over the whole year?

Table 25 summarises several approaches to estimating mean annual solar irradiation: the mean of all 12 months; and the mean of two, three and four months.

Using only January and June data to estimate solar irradiance over the whole year, gives a good approximation for peak clear sky irradiation (with a difference of less than 1% from the whole-year average). For cloudy and "average" conditions, this approach underestimates the peak (midday) irradiance over the year, by approximately 6%. Including one or two mid-season months improves agreement.

For this study, it was considered acceptable to use only January and June data as an approximation, even considering the underestimate.

*Table 25	Average midday irradiation over the year, from PVGIS daily peak values*

	Averaged PVGIS clear sky, Wm^{-2}	**Averaged PVGIS diffuse, Wm^{-2}**	**Averaged PVGIS "global", Wm^{-2}**	**Author's comment**
Whole year	**527**	**158**	**291**	**Target values**
January and June	**530**	**150**	**272**	**Approach used in this study**
Jan, June and September	542	158	288	Recommended approach for further study
Jan, March, June, September	538	164	293	Recommended approach for further study
January and June, with 1.2 weighting for June (and no weighting to January)	**559**	**157**	**288**	**Possible correction for cloudy and average conditions**

In attempting to estimate annual insolation, different weightings could be given to January and June, e.g. 1.2 for June data and 1.0 for January data. Such a weighting improves agreement for cloudy and average days, though it introduces error in estimating clear-sky data.

A more detailed study would include one or two mid-season months, which would result in closer agreement with the annual total. Implications of this are discussed in section 9.5.

7.2. Demand Patterns

The demand profiles generated by the Richardson data are consistent with pattern reported by others. For examples, the pattern of individual runs, and aggregations of 100 runs, described in Sections 5.4, are broadly similar to those reported by Abu-Sharkh et al [29], described in Section 3.2, Figure 5 and Figure 6. The effects on demand profiles of changing numbers of occupants, and types of appliances, discussed in Section 5.4, are consistent with expectations. The patterns of coincident and non-coincident demands also appear realistic. These observations give confidence in the use of these demand datasets for modelling.

Temporal resolution

The use of the same data, at different temporal resolutions, has a profound effect on individual electrical demand profiles, even smoothing from 1-minute to 5-minute resolution, and far more so when using one-hour resolution data, as Figure 38 shows.

Temporal resolution also had a marked effect on maximum demand (kW), shown in Figure 57.

Temporal resolution did not, however, have a noticeable effect on maximum solar generation. It is believed this is because the synthetic solar data have smooth profiles: temporal resolution may have a greater effect if real measured solar data are used, which may change rapidly during the day if conditions are intermittently sunny and cloudy (as shown in Figure 24, for example). It is expected that more stochastic forms of renewable generation, such as wind, could also be more significantly affected by temporal resolution.

It is interesting to note that the *aggregated* power flows were barely affected by temporal resolution. It appears that aggregation itself has a smoothing effect, after which data are not sensitive to further smoothing by change of timestep.

The total quantities of electricity generated and used during the day were not affected by temporal resolution, as expected.

Findhorn case study

The general pattern of demand profiles, summer and winter, for the measured case study data, displayed in Figure 39 to Figure 42, were broadly similar to the synthetic datasets used for comparison. The levels of “spikiness” were similar, as were the approximate quantities of electricity used. The Findhorn data had higher peak power demands than the synthetic, but overall the electricity consumption was significantly lower (Findhorn total demand was 53% of synthetic demand in winter, and 73% in summer). It is not surprising that Findhorn, being an “eco-village” has lower electrical consumption than the general UK population.

It is interesting to note that the aggregated demands in Findhorn did not have an evening peak, unlike the synthetic and UK general electrical demand profiles. The measured data also have higher demands during the night. It may be that the synthetic data underestimate demand during the night, as suggested by the demand model's authors themselves, discussed in Section 3.4, Limitations of Richardson Model. Actual measured night time demand in the Findhorn houses may be to utilise an off-peak (11pm-7am) electrical tariff, which is done in some properties in the village [82]. Other than this night time tariff, there are no formal demand side management arrangements [82]. Some properties have electrical water heating timed to come on in the morning [82], which may well be the cause of the morning peak demand seen in Figure 42. It is not known whether the lack of the evening peak is by chance, or the residents deliberately timing appliance use to coincide with on-site solar generation. A more detailed study would be needed to investigate.

8. Discussion of main results

8.1. Effect of orientation, weather and season on excesses and deficits in generation, in the absence of storage

Effect of season and weather

The effects of season and weather are very strong. It is worth noting that the total day generation on a clear day, on a south-facing slope, in January, is similar to that received on a cloudy day in June (on a slope of any direction): 7kWh for urban scenario.

In winter, "average" and "cloudy" days are relatively similar, with clear days having, in some conditions, significantly lower deficits and higher excesses; the difference is most marked for rural scenarios. In summer, the "cloudy" days are marked by much higher deficits and lower excesses than seen in other weather conditions.

In winter, in urban scenarios, the quantity of electrical generation is minimal in most conditions, an exception being certain orientations in clear conditions. Rural scenarios have three times higher generation, but also significantly higher electrical demands, especially "Rural 1" scenario in which there is storage heating. Thus, deficits are significant in all conditions (mean day totals of around 10kWh for urban, 25kWh for "rural 1" and 15kWh for "rural 2" scenarios). Excesses are low to minimal in most conditions (<1kWh mean day total for urban, and up to ~3kWh for rural scenarios) though significant excesses occur, on clear days only, in rural scenarios (up to 11kWh mean day total) and certain orientations of urban scenarios (up to 5kWh mean day total).

In summer, there is far higher generation, and lower demand, especially in the rural scenarios, because unlike in winter, there is no demand for space heating. Deficits are low (around 5kWh), and little affected by weather conditions, presumably because the night-time demands cannot be met by solar generation, of any magnitude, without storage. In the urban scenario, excesses range from low (around 4kWh mean day total, cloudy conditions) through moderate (mean day total around 8kWh in average conditions) to significant (mean day total around 15kWh, clear conditions). A similar pattern is seen in rural scenarios, with similar mean day total deficits (5-

8kWh), and much higher mean day total excesses (14kWh on cloudy days, 26kWh on average days and 50kWh on clear days).

Thus, excesses and deficits can vary significantly from day to day, and there is large seasonal variation.

The effect of orientation

This was only examined for the urban scenario.

The effect of orientation is minimal on average days, and virtually zero on cloudy days. On clear days, however, orientation does have an effect, described below.

In winter, the effect of orientation closely follows the pattern of day total generation. The difference orientation makes to mean day totals is up to 4kWh for excesses and around 2kWh for deficits. Shady east and west-facing slopes have significantly lower excesses and higher deficits than the other orientations.

In summer, orientation has less effect, presumably because all directions receive direct sunshine for significant periods of the day. The magnitude of variation is up to 1kWh for day total deficits, and up to 3kWh for day total excesses. The small effect of orientation has on deficits appears to be correlate with time-coincidence of electrical demand (for example, east-facing slopes have slightly higher deficits than west-facing). Excesses appear to be affected by both time-coincidence and total generation (west and east facing slopes having the lowest excesses and south and south-east facing slopes the highest).

These orientation effects, up to a few kWh on day total excesses and deficits, are far smaller than effects of weather and season.

8.2. The effect of storage and aggregation on excesses and deficits in generation.

Urban scenarios

In January, on an "average" there is a modest benefit (around half a kWh/day) in installing a small amount of storage (one lead battery), as shown in Section 6.2. The lithium battery system found half a lithium battery reduced deficit by a similar amount to two lead batteries. Installing further storage makes negligible difference. Aggregation of 100 runs, even without storage, is more beneficial than storage. Aggregation with storage is very little different to aggregation without storage. On a clear day, increasing amounts of storage and aggregation do reduce deficits, up to around 4kWh, (though cannot come close to eliminating deficits) with diminishing returns for increasing quantities of storage. Aggregations combined with a small amount of storage achieves close to full benefits of deficit reduction.

In summer, there are greater benefits in installing storage. On an average day, minimal storage reduces deficit by approaching 2kWh/day, and there are additional benefits of increasing storage, though with “diminishing returns”. Aggregation, even without storage, reduces deficit by more than a “minimal” battery, and aggregation with a minimal battery (one lead battery) reduces deficits by more than a factor of two; aggregation combined with a “moderate” battery (2 lead / one half lithium) reduces deficit to a very low level (mean deficit from around 5kWh to less than 1kWh).

Rural Scenarios

In winter, increasing amounts of storage, reduce deficits by up to a few kWh per day, though this benefit is small compared total electrical deficits (around 25kWh / 15kWh mean day total, for rural 1/ rural 2 scenario), as demands, which include for heating, are high. (Results are presented in Section 6.3). Aggregation in combination with a minimum battery (one quarter lithium / one lead) brings full benefit; adding further battery capacity, in an aggregated situation, brings virtually no benefit.

In summer, on average days, even aggregation alone is effective at halving day total deficit, compared to the mean of the 100 individual day total deficits. Installing increasing quantities of storage gives continuing reductions in deficits. With aggregation and a minimum battery, on a day with “average” conditions, deficit is reduced from 6kWh to 2kWh; with aggregation and increased battery capacity, deficit is more substantially reduced. A similar pattern was also seen on clear and cloudy days. On clear days, there are large excesses, many times exceeding the capacity of the storage considered here. In these scenarios, these excesses are not utilised.

Comparison of the two different battery systems

The two battery systems were chosen on the basis of suitability and commercial availability. It is something of a surprise that the effect of one "unit" of storage, i.e. one quarter lithium battery, or one lead battery, and multiples of these "units", is so close for the two types, as described in Section 6.5. This similarity was noted in different scenarios, seasons and weather conditions.

The reader is invited refer to Table 9, which shows that one-quarter lithium battery had very similar net capacity (1.45kWh), to one lead battery (1.32kWh). The lead batteries had approximately half the maximum rate of charge and discharge as the lithium batteries (0.44kW for one lead battery, 0.75kW for one quarter lithium battery). It is interesting that this considerable difference in power constraints has so little effect on performance.

Excesses and deficits can be caused by both power and energy constraints. The similarity in behaviour of these two systems, tells us that it is the *net energy capacity* of the battery that is the most important characteristic. Excesses and deficits due to power constraints, therefore, must be relatively low in total energy, compared to excesses or deficits caused by energy (state of charge) constraints. It may be that many of the high power demands, which exceed battery constraints, tend to last for short duration (as observed from some demand profiles). Alternatively, the two constraints may at times occur at the same time, such as generation on a clear day in summer in the rural scenario, which at times exceeds maximum charge rate, and for part of the time, the battery may also be also filled. Further study would be needed to be sure.

For most following results, lithium storage only is displayed, because the modelling for the lead battery is more approximate, as described in section 4.6.

Temporal resolution

When calculating excesses and deficits, there was very little change by smoothing data from one-minute to five-minute resolution. However, smoothing from one-minute to one-hour did cause measurable reduction in excesses and deficits, by around 20% in some runs, as shown in Figure 58. Clearly, generation and demand which are non-coincident at one-minute resolution, may appear coincident if coarser time resolutions are used, and so calculated deficits and excesses would be lower.

Temporal resolution had virtually no effect on aggregated excesses and deficits.

The effect of temporal resolutions on excesses and deficits in systems where there is storage were not modelled due to constraints of the project. It is expected temporal resolution could cause even greater differences in excesses and deficits, if power constraints of the battery are significant.

There is more discussion in Section 9.4 of the implications of choice of time step in calculations.

Findhorn case study

Measured demand data from Findhorn, and a similar comparison group of synthetic data, for a summer day and a winter day, were processed to obtain figures for predicted day total deficits and excesses in electrical generation. Section 6.8 presents the results (supplemented in Appendix 21). Even though there were differences in the magnitude of day total deficits between measured and synthetic datasets, the deficits and excesses in each group were affected in a very similar way, by the installation of storage, by aggregation, and by combinations of the two. This was the case both in winter and summer.

In all cases, it was aggregation, in combination with minimal storage, which was the most effective approach to deficit reduction. Installing storage on an individual basis brought down deficits in summer, when substantial storage was deployed, but in winter, installing storage on an individual basis had little effect.

Some caution needs to be applied to this case study, because of small size of datasets, and other reasons described in Section 4.9. However, the similarities between behaviour of excesses and deficits, derived from both measured and synthetic datasets, are a cause for cautious confidence in these results.

8.3. The effect of aggregation

Peer-source aggregation (i.e. the connection of multiple similar houses, which are sources of both generation and demand, so that all can utilise generation and stored electricity, when there is any) of 100 runs, for both urban and rural scenarios, was found to bring benefits (in reduction of mean day deficits) comparable with a small battery. Clearly, aggregation by itself works if there is diversification: different households using appliances at different times. Validation of Richardson data by Richardson et al report diversification parameters of modelled data agreed well with measured, and so are considered to be representative of general UK diversification patterns. However, this may not be the case in some communities, for example if most people are out at work during the day and return around the same time.

A preliminary look at different sizes of aggregations, found very small-scale aggregation appears promising. Clearly, there is considerable variation between one group and another. However, an aggregation of six, which could be a tenement close, may bring much of the benefit of aggregation of 100. Further study would be needed to establish this by checking larger numbers of small aggregations. Looking at larger aggregations, 600 runs brought minimal additional benefit compared to 100, in terms of deficit reduction. However, there could well be cost savings in power electronic equipment (inverters, converters) if reduced numbers of such items needed purchased. (Practicalities are discussed in Section 10.5.)

8.4. Cost-effectiveness of using storage and aggregation

Detailed financial analysis is beyond the scope of this project, but it is possible to make some general comments.

Calculations of potential annual revenue, from installation of storage and / or aggregation reported in this study must be treated with caution, for reasons given in sections 4.10, 6.9 and 9.5. However, they provide a first order estimation of the kinds of revenues which could be obtained.

There is considerable variation in estimates of present and future costs of storage.

The additional cost of *installing* storage could be significant, if done as a separate operation from installing the PV system, as suggested in Section 6.10. Estimation of costs (or savings) of aggregation was beyond the scope of this project, as discussed in 6.11. However, it is expected that additional costs of *installing* storage and / or aggregation would be much lower, if done at the same time as installing the PV systems themselves. This is consistent with reports from business and industry, for example [12, 15, 16].

This author takes the view that financial viability would require annual revenues *at least* 10% of capital cost. While battery systems may well last more than 10 years, their output will decline with age, probably slowly in the case of lithium, and possibly more rapidly in the case of lead (discussed in section 10.2). Here *ten years' revenue* is taken as a crude estimate of total lifetime revenue. Maintenance costs are not estimated here, though expected to be small in the case of lithium, (e.g. Table 18) and greater for lead (discussed in Section 10.1)

A comparison of estimated annual revenues, and capital costs, is given in section 6.12 and Appendix 26. These show:

- Capital costs are significant compared to annual revenue. Fairly long payback times are expected in most cases
- Even with current electricity costs (tariff scenario 1, 15p/kWh) there are some examples of annual revenues which exceed 10% of estimate of capital costs. In some cases, annual revenues exceed 20% of estimated capital costs. These scenarios would appear to be approaching, or even at, financial viability.
- In scenarios where electricity unit price is more expensive (flat rate scenario 2) savings with storage and aggregation are proportionately greater.
- Varying time-of-use tariff (TOU scenario 1), with modest variation in tariffs during the day, causes a modest increase in revenues for smaller battery sizes, but no change for large battery sizes. A TOU tariff with higher peak charges (TOU scenario 2, Appendix 26) has far more significant benefits from storage, of all sizes.
- The ability to sell electricity to the grid at peak times would add a significant revenue stream. Here, greatest benefits are seen with larger battery sizes, and higher potential selling price (TOU with sale scenario 2, Appendix 26).

- The rural scenario has about 60% higher annual revenues from aggregation and storage than urban. Higher benefits are expected, as rural scenarios have roughly twice the electricity consumption as urban, and three times the generation. Perhaps the surprise is the benefits are not even greater.
- Lead batteries are currently cheaper than lithium, and may be a good investment, particularly if one wishes to install a small quantity of storage.

The author's recommendation of "best buy", in current circumstances of electricity pricing (flat rate scenario 1) is as follows:-

Aggregation of 100 plus minimal storage[14] Urban and Rural***
Annual benefits to urban scenarios of £120 (flat rate) / £130 (modest TOU tariffs), and £200 (flat rate, rural scenario), with current electricity tariffs. These compare with costs of £500 for a lead battery, and lithium battery cost estimates of £840-£1500, predicted by some to fall to below £500 by 2020.

Other options worth consideration are:-

Aggregation only**
A potentially low cost / no cost option, if done at the same time as PV system installation on multiple houses, especially in a high-density urban environment, or with immediate neighbours in a rural setting. Ideally up to around 100, but much smaller aggregations, in many cases, are likely to bring considerable benefits. Annual projected benefits of £50 (aggregation of six) to £80 (aggregation of 100) in the urban scenario, and £140 (aggregation of 100) in the rural scenario.

Aggregation of 100, medium battery[15], rural scenario only**
Projected annual revenue of £230 compare favourably with £1000 for lead battery / £1680-£2000 for lithium battery.

If aggregation is not practical, the most cost-effective individual storage option is:-

Individual storage plus minimal battery**

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[14] One lead battery or one-quarter lithium Powerwall battery

[15] Two lead batteries, or one-half a lithium Powerwall battery

Projected annual benefits of £70 (urban, flat rate) / £90 (urban, modest TOU tariffs) / £100 (rural, flat rate) would appear to justify a single £500 lead battery, or minimal lithium battery according to some price estimates (£840 / £1053 / £1500) or if prices fall.

It is interesting that these findings are broadly consistent with findings from the Carbon Trust and partners[12] (reported in section 3.6), which recommended aggregation of 90 in combination with minimum battery storage. These studies used different data (Carbon Trust and partners' peak solar generation was lower than used here, and annual electricity demand, which used measured data, had mean annual consumption closer to the rural than the urban scenarios modelled here.) The Carbon trust and partners' modelling methods were very different from this study's too, consisting of a full one-year simulation, with timesteps of one hour. The similarity in findings, despite such different methods, corroborates the findings presented here.

The Carbon Trust and partners[12] differ from this study in conclusions about individual storage. Both studies conclude that installing a full Powerwall system on an individual basis is not currently financially viable. However, the Carbon Trust and partners do not present results for minimal battery installation, perhaps because such items are not readily commercially available in lithium at present. This author does *not* agree with Carbon Trust director Andrew Lever's statement *"It makes no sense to put a battery in our garage... [...to install storage on an individual basis]"*[51, 52, 54] . However, this author does share his sentiment that community-scale storage is highly preferable, if it can be arranged.

Other combinations of storage and / or aggregation become attractive in other circumstances. Some examples are listed below.

- Electricity prices increase (e.g. tariff scenario 2). Revenues would proportionately increase with electricity prices, and other options, with requiring greater investment, become attractive.
- Sale to the grid is possible at peak times. Even with modest rates (TOU with sale, scenario 1) annual revenues from larger battery sizes, even on an individual basis, approach the 10% of capital costs requirement for lead, and some estimates of lithium battery systems.

- Sale of electricity to the grid is possible, with a high sale price. The more futuristic scenario "TOU with sale 2", which has a high peak rate import and export price, has the greatest benefits for largest battery arrangements, some of which found negative annual electricity bills.
- The property owner has capital to invest (particularly in the current, low-interest rate conditions) and is willing to tolerate long payback times
- The property owners are keen to improve autonomy from the grid.

An increase in benefits in the case of TOU tariffs is also reported by the Carbon Trust and partners; they found a greater increase in benefits than was found in this study. (The effect of TOU was not investigated for the rural scenario due to project constraints, and is worth investigating, as benefits may well be greater.)

Finally, capital costs of installing storage could substantially fall, if lithium battery prices fall, as predicted by some, especially if used electric vehicle batteries become available. Also, if the small-scale storage market matures, more operators will be available to install storage, installation prices would be likely to fall. It is possible that either Government or electricity companies may offer incentives for installation of distributed storage (or for domestic or community generators to sell electricity at peak rates at peak times) in an effort to meet renewables targets and stabilise electrical networks. While financial viability of many storage options is marginal at present, some very foreseeable changes in the business environment could make storage eminently viable in the near future.

9. Discussion of method

9.1. Overview of method

This study took data from external sources, for both solar generation, and synthetic domestic electrical demand. Both data sources were examined, as explained in Section 4, and discussed below in section 9.2.

A programme was written to evaluate excesses and deficits in electrical generation, with and without storage, for individual "houses" and for aggregations of "houses".

It is believed this approach has succeeded in estimating excesses and deficits, for one-day snapshots, in summer and winter, in a number of scenarios. While there are limitations with this method, which are discussed below, this approach is believed to be reasonably reliable in obtaining:-

- Estimates of excesses and deficits, for single day in the selected season
- A first approximation of an annual excesses and deficits, based on results for summer and winter.

This approach is considered to have been successful.

9.2. Selection of synthetic data: how suitable are these data?

Solar data

A brief study, comparing PVGIS solar data, used in this model, with real measured weather data, found good general agreement between these two alternative data sources (Sections 5.3, 7.1). This suggests that PVGIS solar data are suitable for use in this model. However, a longer term study could be enhanced by inclusion of measured data to introduce the variability of "weather".

Demand data

To investigate the suitability of the synthetic Richardson data, a small case study was included, in which measured data from the village of Findhorn were examined and modelled in the same way as a comparison group of synthetic data. It was found that both measured and comparison datasets had broadly similar demand profiles (Section

5.7, 7.2) though synthetic data may underestimate night-time demand; if this is the case, there may be slightly underestimates of the value of storage in supplying demands when it is not sunny. However, the general similarities suggest that: the synthetic data do represent real data reasonably well, and so are suitable for use in this project

Though there were differences in datasets, the real and synthetic demand profiles responded in very similar ways to the calculation of excesses and deficits in generation, and the effect storage and aggregation had on these results (Section 6.8, and 8.2 Findhorn case study). These similarities are a cause for cautious confidence in the use of this modelling method.

9.3. Limitations: variables

Below is a summary of the extent to which uncertainties in variables used in the modelling are considered to potentially affect results.

Table 26 Limitations: electrical generation variables - building type

Variable	Limitation	Estimated magnitude of limitation or error
Size of dwelling	Actual urban buildings based on measurements, though actual properties vary in size. A single assumption made for rural: this may well be an underestimate.	Small to significant
Angle of roof	Only one angle used, 35 degrees.	Very small in most cases
% of roof covered in PV panels	An upper bound of 50% used. Does not take into account complex roof structures, or limitations due to size of panels which can be purchased, or limited available capital to invest in PV panels	Probably small for urban, but may be a significant overestimate for rural scenarios
Numbers of flats sharing roof space	The main modelling was done with the Ballindalloch scenario, in which flats consist of 3 storeys. Far more common in Glasgow are tenements 4 floors high. Other designs of flats also exist. Assumptions for rural scenarios are single household under a roof, but some flatted accommodation may exist.	small-moderate

Table 27 Limitations: electrical generation – solar resource

Variable	Limitation	Estimated magnitude of limitation or error
Time of year	Summer and winter were estimated, using June and January data.	Low for summer and winter estimates. Error in extrapolating to make annual estimates may be significant.
Weather	Three types of day were modelled: "Clear", "cloudy" and "average".	Low for single day estimates, and upper and lower bounds of estimations.

Table 28 Limitations: demand variables

Variable	Limitation	Estimated magnitude of limitation or error
location	Climatic differences between Loughborough and Glasgow may affect demands, such as space heating, and appliances (e.g. tumble driers), probably causing an underestimate of demand in Glasgow.	small
location	Daylight differences between Glasgow and Loughborough, estimated up to half an hour at the solstices, will cause an underestimate in demand for lighting in winter, and an overestimate in summer	small
Weather	Cannot specify specific weather (e.g. cold snaps / warm weather), though time of year is used. Particularly relevant for space heating.	small
Time of year	Only two times of year were used: January and June. Inclusion of mid-season demand patterns would be needed for an estimate of annual demands	Minimal for comparisons of winter and summer scenarios. Significant for annual totals
Weekday or weekend	Only "weekdays" was studied here.	Minimal for comparing different scenarios of weekday. May be significant for annual totals.
Occupant lifestyle	Demand data believed representative of a range of UK lifestyles / circumstances. However, this may not represent certain communities. No provision for stipulating type of community e.g. "low income / in work / at home with children" etc.	significant
Appliance allocation	Scenario-based approaches were used here, based on Richardson defaults for appliance allocation, and assumptions regarding space and water heating. These may not represent specific communities.	Small - significant
Number in household	Scenario based approaches were used, based on local knowledge for urban settings (and the author's assumption regarding age of occupants). These may not represent specific communities.	Small – significant

Table 29 Limitations: storage variables

Variable	Limitation	Estimated magnitude of limitation or error
Capacity	lead acid – does not model kinetic behaviour	May be significant
Max charge and discharge rate	Lead acid – does not model kinetic behaviour	May be significant
Minimum and maximum charge	Both batteries: alternative values could be selected to prolong battery life, or exact greater utility	Small - medium
All parameters	Does not model degradation in service	Significant after a few years, particularly for lead
State of charge at start of the day	Assumptions were made assuming either: fixed quantity of charge, fixed state of charge, or an estimate was made based on SOC at end of a day with same parameters. Real SOC depends in part on results of previous run. A longer term study is needed to model this reliably	Small to moderate.

Table 30 Limitations: modelling variables

Variable	Limitation	Estimated magnitude of limitation or error
Number of runs	Chosen to represent different potential size of aggregations.	Low
Duration of run	All runs were for one day, 24 hours. Estimates of longer periods	Low for single day estimates. Could be significant for extrapolations for longer periods
Time step	One minute time step believed to give good representation of changes in electrical supply and demands	low
Numbers of groups of runs of the same number	Only one group of 100 (for summer and winter) and one group of 600 (summer only) were modelled. Two groups of six runs were modelled. Populations of groups will have a spread of results, with greater variation between groups of small numbers.	Fairly low for groups of 100 and 600. Significant for groups of six.

Further discussion of storage variables

As stated in sections 3.5, 4.5 and 4.6, modelling of the performance of battery systems is not straightforward.

The model here has used assumptions of single value for capacity, and maximum charge / discharge rates. For the lithium batteries, these approximations are considered reasonable for “nearly new” batteries. However in the case of lead acid batteries, difference between actual and assumed behaviour is probably greater. The assumption of a single value of capacity and maximum power rate is a major simplification. It underestimates the power the battery can deliver for a short time (for reduced power output) and also, the quantity of energy the battery could provide while delivering small loads.

This study is done in the context of lithium batteries, reported as better performers than lead by several in Section 3.8, being commercially available, with reducing costs (described in Section 3.5). Some researchers [12] do not even consider lead acid batteries in future systems. In this context, it was considered acceptable to use this type of approximate modelling to describe the behaviour of lead acid batteries: these approximations must be remembered when considering results. (Other studies, such as those using HOMER, use a similar, simplified approach, e.g. [67].)

The other parameters selected: efficiency, and maximum and minimum states of charge, were considered realistic, though different values could reasonably be substituted.

This study does not model degradation in service, which is significant for both battery types over a period of years. This matter is discussed in section 10.2.

9.4. Choice of temporal resolution

Richardson et al were of the opinion that modelling with one minute resolution was, in fact, necessary, for an accurate representation of demand [35, 83]. However, many previous studies on this [12, 13, 21, 26, 67, 69] model with a resolution of half or one hour. Clearly, caution must be applied when comparing such studies.

The effects of different temporal resolutions are displayed in sections 5.6 and 6.7, and discussed in section 7.2.and 8.2 Temporal resolution.

It is considered essential to use one-minute data if one needs an accurate representation of individual demand profiles. Lower resolutions appear adequate for synthetic solar generation profiles, though this may not apply to real measured solar data or other forms of renewable generation.

If one is calculating excesses and deficits in generation, it is considered advantageous to use data of one-minute resolution in all calculations here, though five-minute data would probably give very similar results. If only data of half or one-hour resolution are available, they may still be used to estimate excesses and deficits in generation, but one must be aware that these values may be underestimated by up to around 20% (possibly more if storage is present). Further study is needed, especially including storage, to better quantify the range of error.

One-hour data appear perfectly adequate for describing day total generation and demand (in kWh) of individual runs. One hour data also describe, with little error, power flows, and excesses and deficits in generation, for large *aggregations* of data (of 100 demand profiles). It appears that aggregation has a "smoothing" effect itself, and these data are insensitive to further "smoothing" of time step.

In summary

The use of one-minute resolution data is considered a significant strength of this project. It allows accurate description and calculation of energy flows, and excesses and deficits in generation.

9.5. "Snapshot" approach

As stated in earlier sections, this study models single days, in summer and winter conditions, giving "snapshots" of performance, which are compared.

The snapshot approach is a quick way of performing detailed comparisons of different scenarios, at chosen seasons and weather conditions. As the modelling periods are short, it is easy to use high-resolution data, and thus obtain potentially robust results.

There are two potential problems with this approach:-

1) Having all the necessary information to input correct parameters for each run. Here, the only unknown parameter is the initial state of chare (SOC) of the battery.
2) Extrapolating annual totals from two snapshots of one summer day and one winter day.

These are discussed in turn.

Initial state of charge (SOC) of battery

If there is storage present, any charge contained in the battery at the end of the night is available to meet demands the next day, and is particularly valuable for demands during the night and early morning, before there is solar generation.

Thus, to accurately estimate deficits in generation on any day, a good estimate of the state of charge at the end of the previous day is needed.

The difference in day total deficits, from *mean* and *median* SOC representing different weather conditions, was found to be small: up to up to half to 1kWh, as displayed in section 6.4. In several conditions, such as small battery, winter, and cloudy conditions even in summer, the variation was minimal as the SOC was at or near the minimum for all but runs of particularly light demand.

In theory, different houses with installed battery of around 6kWh capacity could have up to 6kWh variation in charge available for the next day. In practice the variation is much lower, for several reasons: -

- Sunny or average conditions in summer (or sunny conditions in winter if demand is light and orientation favourable) are needed to fully charge the battery; which by no means occur every day in Glasgow.
- In most runs, there are several kWh of demand in the evening, after solar generation ceases for the day, so the remaining charge at midnight, even in a battery which was fully charged during the day, is likely to be substantially reduced. This is particularly seen in winter, as demands are greater and days shorter.
- It is the *early morning demands* which need to be met by energy from the battery, as solar generation will substantially provide for demands during the

day in summer. Demands during 00:00-07:00 are, on average, well under a kWh in summer. Without significant early morning demands, there is not a great difference in deficits between houses where initial SOC was high and low.

- In winter, there are greater morning demands, especially where there are heating demands, and as the morning demand peak occurs before sunrise. In theory, this morning demand could cause a big difference in deficits between runs. However, in practice, the sunny conditions needed to charge the battery are exceptional, and demands tend to exhaust the battery.

In short, this type of model can only crudely estimate the initial state of charge. Theoretically, the initial SOC could affect day total deficits by up to several kWh when large batteries are installed, but there are good grounds to expect variations to be far smaller, discussed above, which fits with measured variations in deficits with SOC of up to 1kWh/day, and in many conditions, virtually zero. This approach does underestimate the range of initial SOC between individual runs. It is also possible there may be more variation in deficits with SOC in mid-season conditions, which were not studied.

This source of uncertainty is considered small, but should still be considered. A longer modelling period, over more days, would reduce or eliminate this source of error.

If the study was extended to include much large battery systems, which could store enough charge to meet several days' demand, variations in the initial SOC, and its importance, would be far greater.

Extrapolating annual totals from a single January day and June day

Can a representative winter and summer day be extrapolated to the whole year?

Clearly, extrapolating annual totals from two "snapshots" of a summer day and a winter day (i.e. assuming "half the year is January, half the year is June"), will give approximate results.

Solar data

Section 7.1 subsection “How many months need to be studied to estimate irradiation over the whole year?” is an attempt to judge how well extrapolations from January and June solar data can estimate the whole year, by looking at day total peak solar irradiance values.

Estimations of average peak solar irradiation over the year, from 12 monthly values, were compared with extrapolations from January and June (all PVGIS data). It was found that annual extrapolation from January and June led to a small (~6%) underestimate of average peak irradiation on “average” and “cloudy” days, and much closer agreement on “clear” days. Repeating the estimates, with three or four months, including mid-season months, significantly improved agreement.

Regarding weather variations, the “average day” PVGIS data appeared to agree well with observed weather data, and were considered reasonable for use in estimation of total irradiation.

Demand data

No investigation was made as to how well annual demand can be represented by a summer and a winter day. This is particularly important in the rural scenarios, where there are high seasonal variations in demand due to winter space heating. The length of the heating season is therefore, an important variable, which was not investigated.

In short

The snapshot approach appears to underestimate annual solar resource by a modest amount, <10%. It is not known if this approach under or overestimated annual demand.

Assessment of the “snapshot” approach

Despite the uncertainties of initial SOC described above, this “snapshot” approach is considered to give reasonably robust estimates of excesses and deficits on single day, based on high-resolution input data. Form these, valid comparisons of the effect of different storage and aggregation, in summer and winter, can be made.

However, extrapolations from these single day snapshots, into annual totals, must be viewed as first order estimates. ***This factor is believed to be the greatest limitation of***

this study. However, these annual estimates are believed to be good initial approximations, on which one could sensibly decide if the topic merits further study.

Suggested modifications

The approach could be improved by:-

- Inclusion of a greater number of “snapshots” from different months. Even addition of one or two mid-season months (ideally up to one for every month) would give more reliable annual totals.
- Modelling of periods longer than a single day, and using real weather data to augment or replace PVGIS data (e.g. a week of “cloudy” weather, or days of intermittently “sunny” and “average” weather), to simulate performance with real weather patterns
- Ideally, performing a full annual simulation, with real weather data, would yield the most reliable results.

10. Discussion of practical and economic matters

10.1. Battery maintenance

Lithium ion batteries sold for domestic use are promoted by manufacturers and suppliers as being “maintenance-free”. More widespread, longer term use of such devices will contribute to our knowledge of how they actually perform in use.

Many type of lead-acid batteries, on the other hand, do require maintenance and specific operating conditions to avoid premature ageing. There are maintenance-free batteries available, but they have much shorter service lives. The manufacturer of the battery used in this study, a Rolls Surette, has a manual available for download [76], over 40 pages in length. Some householders will wish to carefully maintain their batteries, but many will not; a professional service contract may be realistic, which will add to costs. It is imperative that batteries are not left in an empty state of charge, which would be likely using small numbers of batteries are installed, in winter conditions, and even on cloudy days in summer in urban scenarios. Electrical control systems will need to protect batteries from damaging low states of charge, and it may be prudent to disconnect the batteries altogether during the winter months.

The issue of maintenance may be handled better by organisations than individuals. For example, if installed by a large property owner, such as a housing association, or university (owning halls of residence), there would be a person or department responsible for property maintenance, whose duties could be extended to include battery maintenance. Alternatively, in a community electrical generation scheme, a management committee or trust would normally be responsible for maintenance.

In short, it is considered that aggregated storage systems may be more easily maintained than individual systems, though individual systems owned by enthusiasts will be possibly the best maintained of any.

10.2. Battery lifetime

Lithium ion batteries have a ten year warranty [72, 73], and suppliers suggest a lifetime of around 5,000 to 6,000 cycles, depending on mode of use [72, 80]. (Appendices 10-11 display some of these details.)

The selected lead acid battery also has a ten year warranty. The number of cycles depends very strongly on charging / discharging behaviour [75, 76]. According to the manufacturer, operating in conditions where the minimum charge is 20% (i.e. an 80% depth of discharge), the battery should have a life of 2000 cycles. (For comparison, 95% depth of discharge ~ 1500 cycles; 30% depth of discharge ~ 4000 cycles, displayed in Appendix 14.)

The battery warranty, included with one Powerwall supplier [80], states the useable capacity will decline, but to no more than 60% of initial capacity after ten years (or a stated number of cycles / quantity of lifetime energy delivery, if earlier), as shown in Appendix 12. Given the shorter life of lead batteries, in terms of number of cycles, a faster decline in capacity for these is expected.

This study assumes ten years of operating life from the batteries. Clearly, this is a fairly crude approximation of lifetime performance. Using the batteries in different conditions to those expected could greatly alter their life, as discussed in Section 3.5, particularly in the case of the lead batteries. This study also assumes the capacity of the batteries will not change over the ten years, which is clearly also an approximation.

It is worth noting that the "best buy" recommended in section 8.4 is for *minimal* capacity of storage, so batteries would normally be fully discharged during the evening, and remain in a minimum state of charge until the next day, or possibly many days or weeks later in cloudy winter conditions. These are demanding operating conditions for batteries. It is essential to ascertain whether the batteries can actually tolerate this pattern of use, and to estimate their service life in these conditions.

10.3. Space for storage

Battery size

Lithium ion:

L G Chem:	406mm * 664mm* 165mm.	Weight:	60kg.
Tesla Powerwall:	1300mm * 860mm *180mm.	Weight:	97kg
Source:	[72, 73], Appendix 12 and 13		

Numbers investigated: one quarter, one half, and one full-sized battery.

Lead acid:

Rolls Surette	559mm* 210mm* 464mm.	Weight:	100kg.
Source:	*[75]*, Appendix 14.		

Numbers investigated: one, two and four.

One lithium battery was found to be approximately equivalent to four lead acid batteries.

Individual storage

In high-density urban areas, living spaces tend to be fairly small, with little spare room for storage. Thus, any storage requiring large (or for some households, any) space in individual houses is not likely to be very attractive. However, a Tesla Powerwall, for example is designed to fit in a modern house, and may be acceptable. (Of course, other equipment, including inverter and probably a converter would also be needed.)

In suburban and rural areas, small houses do exist, but it is more common for there to be space in or around the house (e.g. a garage or a shed) so finding a space for storage is probably easier.

Communal storage

In urban areas, considering installing storage for a single close of six or eight flats, there may indeed be a communal loft space, or cupboard in the communal stairwell; in many cases there is a small shared garden or “drying green”. Whether such spaces would be suitable, for reasons of size, accessibility and security, would depend on local circumstances. It may even be necessary for storage to be distributed between flats, though connected to a joint system.

Considering a system of one hundred dwellings, it may be more practical to find an area sufficient to house the storage system.

10.4. Storage types

The modelling was confined to two types of storage: lithium ion and lead-acid, being commercially available, and considered suitable for use in houses [26] as discussed in section 3.5.

However, the above section also includes other types of storage, including sodium sulphur, ZEBRA, and redox flow batteries. While not considered generally suitable for use in domestic properties, for reasons such as high operating temperature or large space requirements, alternative systems could be practical for community-based storage. Examples in practice include a vanadium flow battery storage system for the Isle of Gigha [18], and a 500kW Na-S battery in the Aichi microgrid project in Japan [32]. Thus, aggregating storage brings the potential benefit of alternative storage media, which could be attractive.

10.5. Size and circumstances of aggregated "community"

An individual householder can decide to install renewable generation, possibly with storage, based in individual desire, available finance, and economic conditions which make such a scheme viable. While this involves personal research and organisation, it is very possible, evidenced by the increase in PV panels in roofs

Obtaining agreement for a collection of individuals would be less straightforward.

In privately owned tenement flats, a very common housing type in Glasgow (for example, see Figure 15), in which all six or eight owners in a close have a joint ownership of and duties covering common areas (e.g.to fix the roof), it is not always straightforward to get agreement and payment for necessary common repairs. Installation of rooftop PV panels would require the consent of all owners in the close, which may not be easy. However, if agreement for such as scheme was reached, an aggregated system, on a tenement close of six or eight flats, would be a natural unit size. System design is beyond the scope of this project, but adding communal storage is not expected to greatly increase complexity of a PV scheme: a joint storage scheme may even be simpler than installing storage on an individual basis. Section 6.6 shows projected benefits in deficit reduction from even such small aggregations. A peer aggregation on this scale, with, and even without storage, is considered potentially feasible.

Larger aggregations, in an urban setting of privately owned houses is not considered realistic, because of the complexity in getting agreement.

However, there may be exceptions. Some close-knit rural communities, e.g. Isle of Gigha, do have work underway to build a joint storage scheme to complement locally generated wind power, on an island with significant grid constraints [18]. Findhorn, a rural eco-village, also has communal energy systems. If a future urban "eco-community" existed, they may also wish for such a scheme.

Accommodation owned by organisations is a different matter, and may present far more opportunities. The urban housing "Ballindalloch" (Figure 14) is a street in which most properties are owned by Milnbank Housing Association (MHA)[84], with a minority of flats in private ownership[16]. Privately owned flats have MHA as their factor[17, 18]. In this type of setting, major changes are possible. For example, the external cladding, to improve thermal insulation, was put on the whole street around 2010-2012, organised by the association[19], as part of a programme of major property improvements[20]. Private owners were required to contribute financially, though

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[16] This ownership pattern follows the historic "right to buy" UK Government policy, in which council house tenants could buy their homes, at favourable prices. This policy has since been discontinued in Scotland.

[17] A *factor* organises and implements common services and repairs (e.g. to the external fabric of the building). Private owners are required to pay the factor for their share of costs.

[18] The author, a resident and flat-owner herself, finds this arrangement works very well.

[19] Work was organised by Glasgow Housing Association, who owned the properties at the time. Ownership was later transferred to MHA.

[20] The decision was taken by majority vote in each close: as GHA / MHA owned the majority of properties in most or all closes, the decision in every close was to proceed.

grants were available towards costs. The work went ahead. This example demonstrates that, if such an organisation wishes to install (and maintain) solar PV or some other renewable generation, with or without communal storage, it is indeed practical to do so. Similarly, a university could decide to install PV (with or without storage) to its halls of residence.

Thus it is believed realistic for aggregated renewable generation (peer aggregation) incorporating aggregated storage, to be organised, in settings where either:-

- an organisation (e.g. housing association) owns the properties, or
- the community is close-knit and enthusiastic, and prepared to organise the work (examples tend to be remote rural areas), or
- the community is an eco-community, or
- the size chosen is small enough to get agreement (e.g. one urban tenement close of six or eight households).

Implementing large aggregated energy schemes within mainstream, privately-owned housing is expected to be far more challenging, due to complexity of getting agreement, and the dedication needed for the necessary organisation.

A summary of some features of individual and aggregated storage systems is displayed in Table 31.

Table 31 Comparison of features of individual and aggregated storage systems

Feature	**Individual**	**Small aggregation (around 6-10)**	**Large aggregation (around 100 or more)**
Storage type	Limited to batteries: Li or Pb.	Probably as for individual	Other systems may become feasible, e.g. redox, Na-S
Storage maintenance	Probably need maintenance-free kit, or a service contract.	Possibly as for individual; more likely to be a resident who is happy to do this	Probably the responsibility of an organisation, which may simplify arrangements
Space	Limited in urban scenario, may not be an issue in rural scenario	Probably still limited in urban scenario, but not limited in rural scenario	Even in high density urban areas there is more likely to be a suitable space.
Length of connections	Minimal	Minimal in urban scenario. Up to a few hundred metres in rural scenarios	In urban scenarios, a few hundred metres would connect around 100 households, with no need to cross roads. Rural and larger urban aggregations would require several km of connections.
Peak power (coincident): Generation	2.5 kW(urban)/ 6.3kW (rural)	~15kW urban ~kW rural (both agg's of 6)	~250kW (urban, agg's of 100) ~630kW (rural, agg's of 100) ~1500kW (urban, agg's of 600)
Peak power (coincident): Demand	~15kW (urban) ~17kW (rural)	~15kW (urban, agg's of 6)	~110kW (urban, agg's of 100) ~220 kW (rural, agg's of 100) ~470kW (urban, agg's of 600)
Size / difficulty of project	Moderate. Householder required to do all own research and organisation.	Urban – probably no greater than organising individually. Rural – adds to the logistics.	Up to 100 in high-density urban setting is not a major project (a few hundred metres, no roads to cross). Larger aggregations would add to complexity. This kind of number in a rural setting would be a much more substantial type of project.

11. Discussion of scope of project

This study had a limited scope: to study the effect of storage and aggregation, in certain scenarios, and the economic benefit in terms of reduction of the need to purchase electricity. While there were benefits, they tended to be modest compared with the likely capital investment, and payback times of many years would be needed. There are numerous aspects of generation and storage system which were not studied, and other ways in which storage could potentially be used. A brief discussion follows.

Capital cost of renewable generation

The cost of the solar panels and associated equipment was out of scope; it was assumed that the generation was there, or about to be installed, and that an option of additional storage was being considered. However, clearly, the size and type of renewable generation is at least in part a financial one, and considering the costs of a whole system, generation as well as storage, is necessary when deciding whether to and what system to install, In practice, decisions of storage and generation may well be interlinked.

Solar thermal generation and thermal storage

While thermal generation and storage were out of the scope of this study, because of project constraints, if electricity is used for heating and / or hot water, as is the case for the rural scenarios, replacing some of the solar PV panels with solar thermal generation may well be a more cost-effective and energy-efficient approach to water heating.

While thermal storage was also out of scope of this project, it would seem likely that storing electrical energy directly as heat, towards meeting a heating demand, would be beneficial, and would make more sense than storing in batteries to use for heating later. Similarly, in houses where there is storage heating, it makes little sense to store energy in batteries, to use to charge storage heaters at night. This is an obvious case where re-timing devices (in this case storage heaters) to make use of any daytime generation peaks, would be worth doing before installing batteries. It is noted that Gandarillas found thermal storage (in hot water tanks) to be cost-effective, but not electrical storage [69].

Demand side management (DSM)

Hersent et al wrote *"The current credo of electricity operators: '**demand is unpredictable – our expertise is to adapt production to meet demand**' is about to be reversed into '**production [from renewables] is unpredictable, and our expertise is to adapt demand to production**."'*[10]. How willing or otherwise domestic consumers would be to rescheduling their use of electricity, to coincide with renewable generation, was not studied here. However, it is obvious that some appliances, such as washing machines and dishwashers (and as discussed above, storage heaters), may be rescheduled without major inconvenience; on the other hand, avoiding cooking, lighting or television at desired times would be very disruptive.

Implementing any DSM, even for only for limited number of electrical demands, would clearly contribute to reduction of excesses and deficits, without the capital cost of installing storage. If time-of-use tariffs come in, that would provide financial incentives to do so. Clearly, DSM could be a useful addition to aggregation and / or storage, and would be worth exploring.

Future electrical demands: heat pumps, electric vehicles

Such demands were not studied in detail, mainly because in urban scenarios, there is little excess electricity to meet additional demands. However, in rural scenarios, there are considerable excesses in summer, on average and especially on clear days. During this time of year there is a demand for hot water but not space heating. Electrical vehicles could be a suitable use for such summer excesses. It is noted that even in summer, there is little excess on cloudy days, and so this energy source would not be available every day, but could be a significant contribution during the season.

Heat pumps may be a suitable application mid-season, when there would be significant solar generation (on clear days, at least), but still a demand for space heating. This would be a useful area for further investigation.

Other services storage could provide

This study considered very limited "behind the meter" benefits that aggregation and storage could potentially provide, in terms of lowering domestic electricity bills.

From the perspective of a distribution network operator, storage has the potential to offer services. Widespread distributed storage could potentially play a part in this.

Ratnam et al note that storage would be operated differently, if the aim was to maximise benefit to the individual household (through reduction in bills), or to the network (for example by reducing peak currents, or reverse power flows at times of high local renewable generation) [28]. She believes, however, that careful system and parameter selection could ensure all parties benefit significantly.

The Carbon Trust and Imperial College model financial benefits that domestic generators could receive, by offering services such as Primary Frequency Response, and Network Support, which could be possible in a future smart grid context [12]. These services could potentially provide additional revenue streams to domestic generators, revenue which would make storage more financially attractive.

Finally, the possibility of using storage, in the context of time-of-use tariffs, has only briefly been explored in this study, with and without the possibility of sale of electricity to the grid at peak times. Potentially, even without generation, with storage one could buy cheap off-peak electricity, for use during times of higher prices, and sell stored energy back to the grid during peak times. Further study in this area is recommended.

In summary

This study has looked at a very limited range of potential benefits from electrical storage. There are other types of storage, and other ways it could be used, which are likely to provide significantly greater benefits than those modelled. Electrical storage would appear to have greatest potential in a smart-grid context, where it could provide services to the network as well as the household. Potentially used in conjunction with thermal storage, and DSM, electrical storage could benefit both consumers and electricity networks, in a future low carbon electricity system.

12. Conclusions

1. In households with solar renewable generation, significant deficits in domestic generation, and in some cases, also excesses, occur at different times during the day. Houses therefore need to import electricity from the grid to meet demands. In the no-feed-in-tariff scenario assumed here, households gain no benefit from excesses in generation.

2. Installation of storage can reduce excesses and deficits, and in some cases, eliminate them, allowing much better use of the home-generated electricity, and reducing the need to purchase electricity from the grid.

3. *Peer source aggregation* of households, (i.e. electrical connection of a group of households, which have electrical generation, in a way that enables all to access shared renewable generation, and stored electricity, when there is some), in some circumstances can be effective in reducing excesses and deficits in generation, even without storage. This happens when there is *diversification*, i.e. different households having electrical demands at different times.

4. Aggregations of 100, in combination with storage is particularly effective at reducing excesses and deficits in generation. Small scale storage in combination with aggregation often brings similar, or greater, deficit reduction, than installing larger battery capacity on an individual basis.

5. Much smaller aggregations, such as of six, bring benefits, which could approach those gained by aggregations of 100. Benefits of small aggregations will vary from group to group, and may be lower if all members have similar lifestyles and patterns of appliance use (i.e. less diversification). Larger aggregations (of 600) bring little additional benefit in reduction of deficits.

6. Aggregation alone (of 100) could bring revenues, estimated at £80 per year in the urban scenario, and £100 per year rural scenario. Aggregations of six were estimated to bring slightly lower, and varying benefits. This may be an option worth considering, as it could be low cost / no cost option, if done at the same time as PV systems are installed on multiple houses.

7. Storage is currently fairly expensive, and fairly long payback times (> 10 years) are expected for many systems. However, it is believed some arrangements are financially viable, or very close to being viable, at present.

8. Storage and aggregation (separately and in combination) brought greater benefits to the rural scenario, which has both higher demands and higher generation, than the urban scenario. However, benefits were significant for both urban and rural scenarios.

9. The most financially viable options was found to be: *minimal storage* (around 1.5kWh net capacity, equivalent to *a quarter* of a Tesla Powerwall), *in combination with aggregation*. This finding is consistent with other research on this matter. This arrangement is estimated to bring annual revenues, with current electricity prices, of around £120 (urban scenario) / £200 (rural scenario). Compared with estimated battery costs of £500 (lead) and £840-£1500 (lithium), it is believed some options are viable.

10. If aggregation is not possible, the best financial option for storage on an individual basis, is again with minimal storage, which would bring estimated annual revenues of £70 (urban scenario) / £100 (rural scenario). There appear to be viable, or very near-viable, options for implementing this at present.

11. When storage is installed on an individual basis, installation of larger quantities of storage leads to greater reductions in electrical deficits, and thus brings higher revenues, compared to installing smaller storage capacities. However capital costs are much higher, and payback times would be longer. When storage is installed in combination with aggregation, increasing quantities of storage often bring little further benefit in deficit reduction and revenue.

12. Increases in electricity prices, introduction of varying time of use (TOU) electricity tariffs, and in particular, the ability to sell electricity to the grid at peak times, all increase revenues from storage, and improve its financial viability, especially of arrangements with larger amounts of storage. These findings are consistent with other research. Storage could also be used in other ways, especially in a future smart-grid context, which were not studied here, but would be expected to make storage more economically attractive.

13. Costs of storage are widely expected to fall, especially if electric vehicles enter mainstream use. Storage could then potentially payback in a few years.

14. Widespread implementation of small scale storage has the potential to bring benefits to a future low-carbon electrical grid, as well as the householder, especially in a future smart-grid context.

15. The method employed in this study were considered reliable in examining "snapshots" of single days in winter and summer. Extrapolations from these "snapshots" to estimate annual totals (energy, financial) are considered to give good *first approximations*. However, study of a greater numbers of seasons, and preferably longer term simulations, would be needed for reliable annual totals.

16. It is considered highly beneficial to model at one minute resolution, in order to retain detail of electrical demands, which change significantly on this timescale. Many other studies model at half or one-hourly resolution, so comparisons must be made with caution. A brief look at temporal resolution found that smoothing one-minute resolution data to one-hour, caused underestimates in excesses and deficits in generation, by up to around 20%, for individual demand profiles. Excesses and deficits of aggregated demand profiles were very little-affected by temporal smoothing. Smoothing data to five–minute resolution did not have a noticeable effect. This brief look at temporal resolution was only *without storage*; the effect may be exacerbated when storage is included.

17. Synthetic data from the Richardson model were compared with real measured data in a case study, and considered suitable for use. The method of calculating excesses and deficits, using both types of data, appears robust.

18. PVGIS solar data used in this study were compared with some measured weather data, and are considered reliable. However, they do not give weather patterns. Further study, augmenting PVGIS data with real weather data, would be useful.

19. When comparing different types of battery, the important feature *is net energy capacity*. Different battery types, with similar net energy capacity, resulted in very similar modelled results, even though the two systems had very different rated power constraints.

20. Deep cycle flooded lead acid batteries, appear the most financially attractive option at present, particularly for small quantities of storage. Lithium batteries have fallen in price, and some predict they will soon be cost competitive with lead.

21. Both the lead and lithium batteries studied are guaranteed for ten years, subject to operating conditions, with estimated number of cycles being ~2,000 (lead) and ~5,000 (lithium). However, the recommended "best buy" storage option is very demanding for the battery systems. It is essential to check that the batteries will tolerate such conditions, and what the actual service life of these batteries might be. This is particularly important for the lead battery option.

22. Aggregation can bring a number of benefits, aside from reductions in deficits in electrical generation, and so reduced electricity bills. Examples include:-
    a. Wider choice of electrical storage system
    b. Potentially reduced cost of power electronic equipment and storage equipment due to bulk orders
    c. Possible simplification of maintenance arrangements

23. Potential hurdles in arranging an aggregated system include obtaining agreement from all participants, particularly if the number is large. This may be easier to do in the following circumstances:-
    a. There is a single owner of all properties, such as a housing association, or a university which owns halls of residence.
    b. The community is close-knit and keen to work together on the project.
    c. The community is an eco-community.

24. Aggregations of 100 in a dense urban setting would span little distance and probably would not entail major logistics; this number in a more dispersed rural setting would require greater distance, project planning and presumably costs. Aggregations of six or eight, which could be a single tenement close, or immediate neighbours, could bring significant benefits and may be much easier to arrange. Larger aggregations would be expected to have greater logistical challenges, and bring little benefit in terms of deficit reduction.

13. Recommendations for further work

Extend the study to include more seasons, and / or longer-term modelling

This study looked in detail at performance over a single day in summer and winter: annual extrapolations derived from these must therefore be considered approximations. This method could, however, be extended to include a larger number of months, at other seasons, for more accurate annual estimates. Furthermore, modelling of periods longer than a single day would allow simulation of weather patterns, which would further improve accuracy. Ideally, a full annual simulation would give the most robust annual totals.

Further study of small groups of aggregations

This study found aggregations of six appear promising, and may be more realistic to implement than larger aggregations. Given the potential benefit, and variation between different groups of such a small size, further work to quantify benefits is recommended.

Other types of renewable electricity generation

This study only looked at solar photovoltaic generation, as this was considered the most appropriate for a high-density urban environment. Clearly, in less densely populated rural locations, other source of generation, such as wind, or micro-hydro, may be advantageous. A further study could investigate the effect of aggregation and storage on different scales, with other sources of generation.

Inclusion of direct solar thermal generation and thermal storage

Direct thermal generation, and thermal storage were not studied due to the constraints of the project, but both of these could be used in conjunction with electrical generation electrical generation and storage, where there is a heating demand met in part by electricity. These features could complement the above study.

Future patterns of electrical demand

This study only examined current patterns of demand. It would be useful for further study to add likely future changes, such as uptake of heat pumps and electric vehicles.

Diversification of electrical demand

Little published work was found on the likelihood of different households having coincident demands, or not. Development of the Richardson model of synthetic data, to allow input for different household types (e.g. adults out at work during the day, at home with young children, unemployed, retired, shift-worker etc.) would be a very valuable extension.

Further study on other types of electricity pricing, and electricity import and export

For the most part, this study assumed all properties are grid-connected, and the tariffs do not vary during the day, and that there is no payment for any exports to the grid. A brief study was done on: two alternative flat rates for electricity, two varying Time of Use (TOU) electrical tariffs, and two scenarios in which electricity could be exported, at peak times only, in return for payment. TOU tariffs, and especially, any opportunity to sell to the grid, were found to improve financial viability of storage.

Further study into such scenarios, which are considered not unlikely in a future grid, is considered worthwhile.

Consideration of impacts on, and services to, the electricity grid

The study only considered benefits and costs to consumers of electricity, individual and small communities. Consideration of impacts of renewable generation on the wider electrical grid was not studied, but is clearly important. In a future smart grid context, the potential of storage to offer further services, such as stabilisation of voltage and frequency, could provide further revenue streams. The extension of the study to include such possibilities would be valuable.

Consideration of lifetime energy and environmental demands of storage devices and other grid components

Energy is needed to manufacture, transport, and recycle or dispose of storage devices and other equipment at the end of their lives: there may be energy demands during their operation too. It would be valuable to perform Life Cycle Assessment to quantify the embodied energy cost, and other potential environmental issues, associated with the storage devices and other grid equipment.

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Appendices

CONTENTS

APPENDIX 1 SAMPLE OUTPUT OF SOLAR DATA FROM PVGIS:

For Glasgow, January, 35 degree inclination, south facing

```
Latitude:   55°51'51" North,
Longitude:  4°15'6" West

Results for:      January

Inclination of plane:    35    deg.
Orientation (azimuth) of plane:      0     deg.
Time        G           Gd          Gc          DNI         DNIc
08:37       54          26          151         62          283
08:52       71          34          206         77          349
09:07       89          42          265         91          411
09:22       107         50          326         103         465
09:37       121         55          374         113         511
09:52       134         59          419         121         548
10:07       146         63          459         128         579
10:22       156         66          495         133         605
10:37       165         69          526         138         625
10:52       173         71          552         141         642
11:07       179         73          573         144         654
11:22       183         74          588         146         664
11:37       186         75          599         148         670
11:52       188         75          604         148         673
12:07       188         75          604         148         673
12:22       186         75          599         148         670
12:37       183         74          588         146         664
12:52       179         73          573         144         654
13:07       173         71          552         141         642
13:22       165         69          526         138         625
13:37       156         66          495         133         605
13:52       146         63          459         128         579
14:07       134         59          419         121         548
14:22       121         55          374         113         511
14:37       107         50          326         103         465
```

```
14:52        89          42          265         91          411
15:07        71          34          206         77          349
15:22        54          26          151         62          283
15:37        37          19          99          46          210

G: Global irradiance on a fixed plane  (W/m2)
Gd: Diffuse irradiance on a fixed plane  (W/m2)
Gc: Global clear-sky irradiance on a fixed plane  (W/m2)
DNI: Direct normal irradiance   (W/m2)
DNIc: Clear-sky direct normal irradiance  (W/m2)

PVGIS (c) European Communities, 2001-2012
```

APPENDIX 2 DOMESTIC ELECTRICAL DEMAND (SYNTHETIC DATA). INPUT TO AND OUTPUT FROM THE RICHARDSON MODEL: AN EXAMPLE OF ONE RUN.

Below are excerpts only, for one run. Full sheets are available at: https://dspace.lboro.ac.uk/2134/5786

Inputs to the model

Domestic Electricity Demand Model - Single Dwelling Simulation Example for 24 Hours

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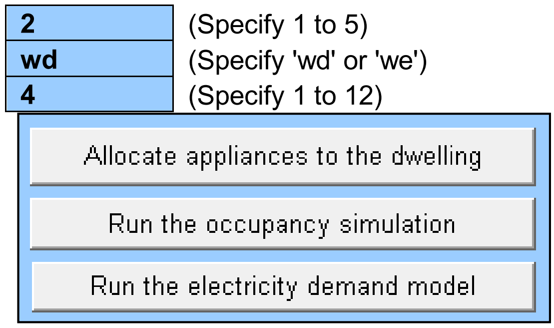
Steps:

1 Specify the number of residents in the house:

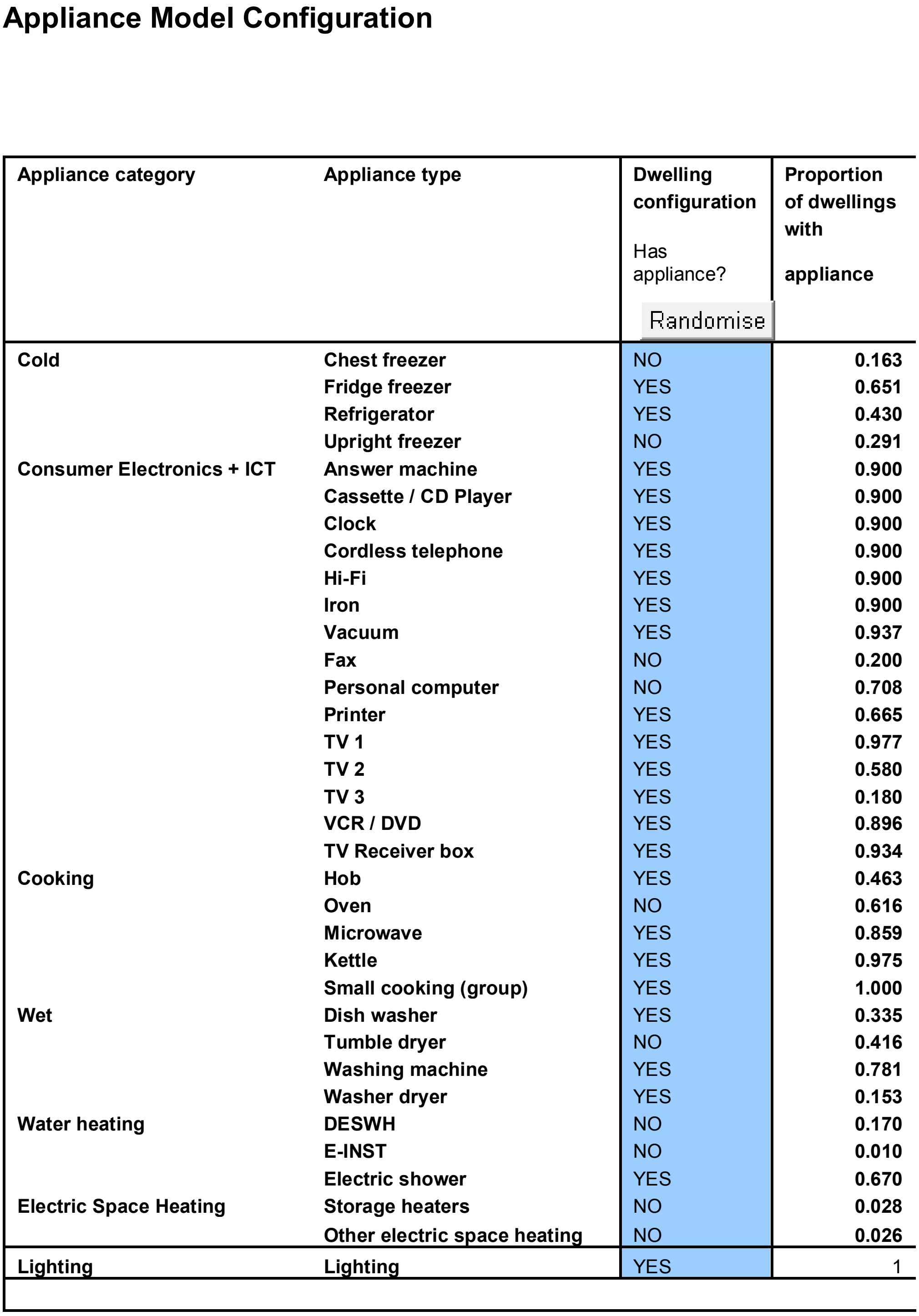
2 Specify either a weekday (wd) or weekend (we):
3 Select the month of the year:

4 Randomly allocate appliances to the dwelling
(or manually specify these on sheet 'appliances')
5 Run the active occupancy model

6 Run the electricity demand simulation
(including both the lighting and appliance models)



2 (Specify 1 to 5)
wd (Specify 'wd' or 'we')
4 (Specify 1 to 12)

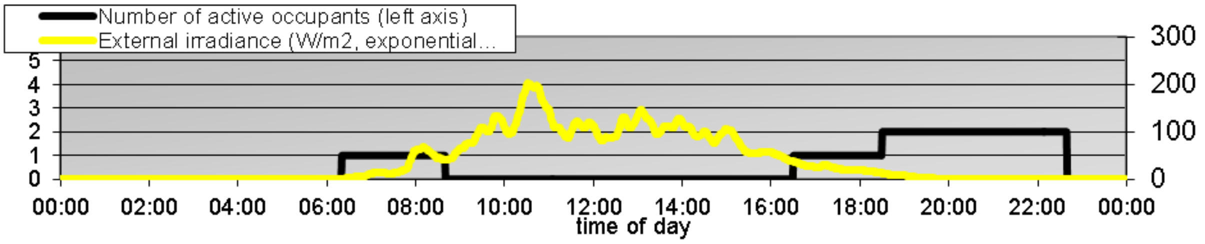


Appliance Model Configuration

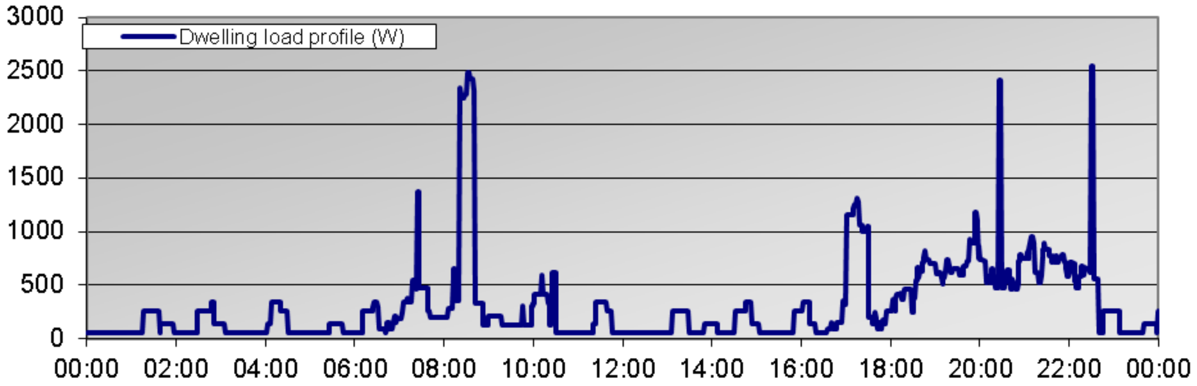
Appliance category	Appliance type	Dwelling configuration Has appliance? Randomise	Proportion of dwellings with appliance
Cold	Chest freezer	NO	0.163
	Fridge freezer	YES	0.651
	Refrigerator	YES	0.430
	Upright freezer	NO	0.291
Consumer Electronics + ICT	Answer machine	YES	0.900
	Cassette / CD Player	YES	0.900
	Clock	YES	0.900
	Cordless telephone	YES	0.900
	Hi-Fi	YES	0.900
	Iron	YES	0.900
	Vacuum	YES	0.937
	Fax	NO	0.200
	Personal computer	NO	0.708
	Printer	YES	0.665
	TV 1	YES	0.977
	TV 2	YES	0.580
	TV 3	YES	0.180
	VCR / DVD	YES	0.896
	TV Receiver box	YES	0.934
Cooking	Hob	YES	0.463
	Oven	NO	0.616
	Microwave	YES	0.859
	Kettle	YES	0.975
	Small cooking (group)	YES	1.000
Wet	Dish washer	YES	0.335
	Tumble dryer	NO	0.416
	Washing machine	YES	0.781
	Washer dryer	YES	0.153
Water heating	DESWH	NO	0.170
	E-INST	NO	0.010
	Electric shower	YES	0.670
Electric Space Heating	Storage heaters	NO	0.028
	Other electric space heating	NO	0.026
Lighting	Lighting	YES	1

Outputs from the model

Irradiance and active occupancy for a single dwelling (24 hours)



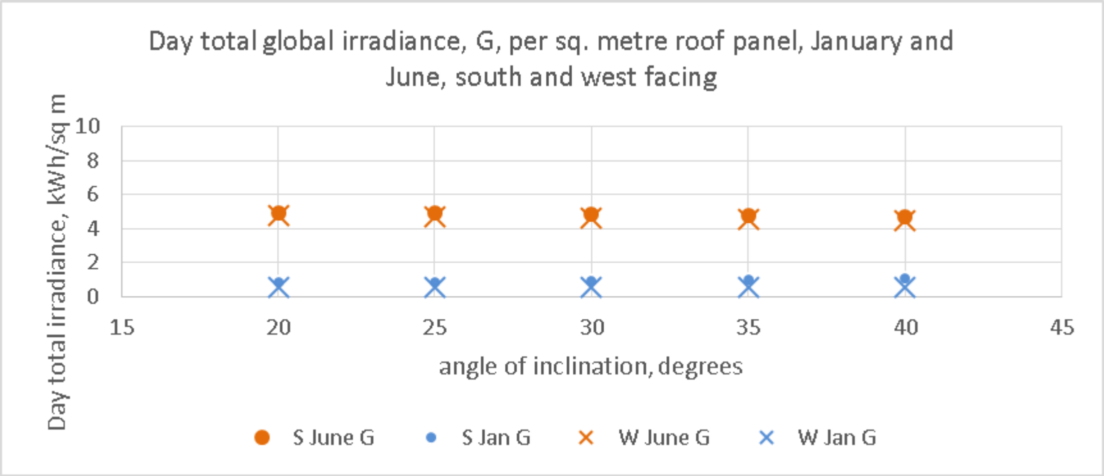
Load profile



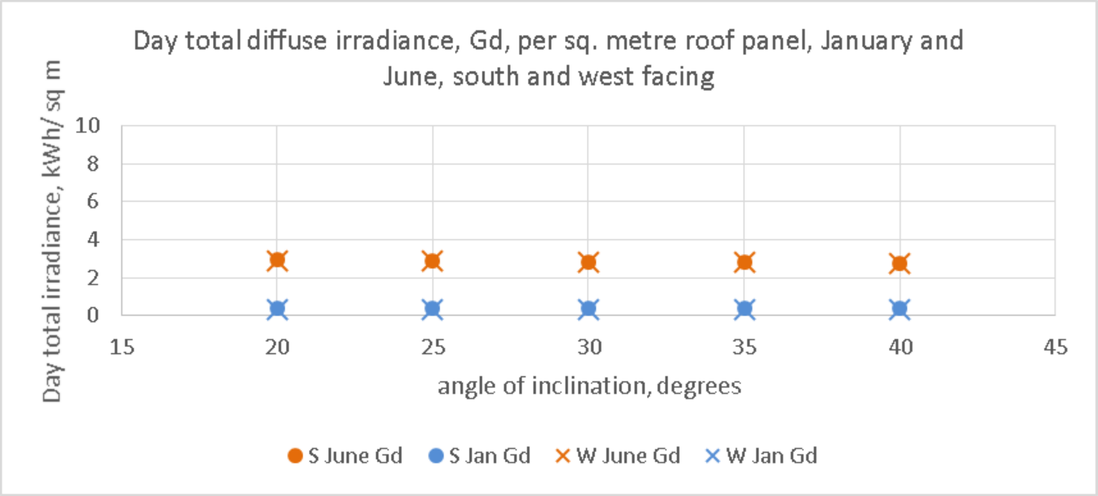
APPENDIX 3 EFFECT OF ROOF ANGLE ON THE QUANTITY OF SOLAR RADIATION. SOUTH AND WEST-FACING, JAN & JUNE

Day totals of solar irradiation energy (kWh/square metre)

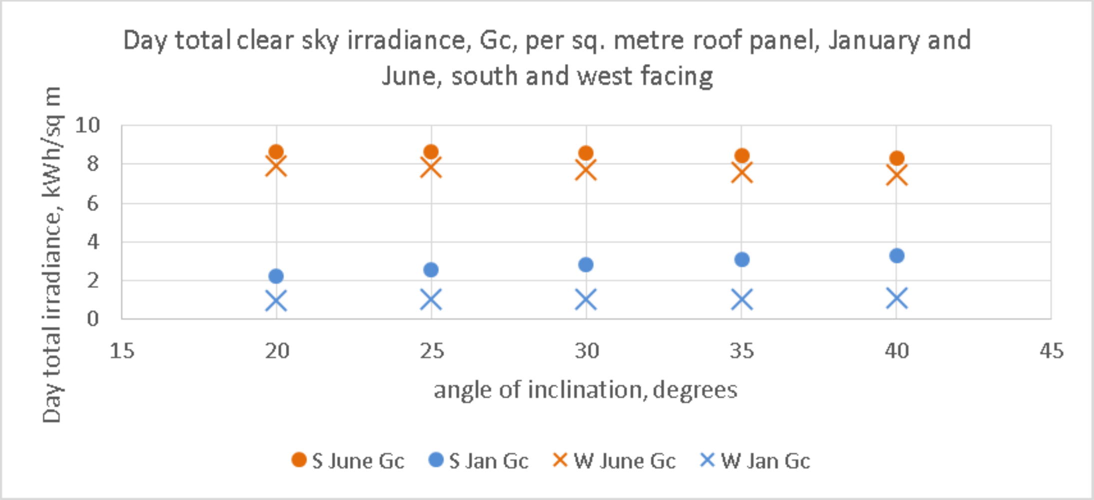
Day total energy, per square metre of inclined panel / roof



Day total global irradiance, G, per sq. metre roof panel, January and June, south and west facing

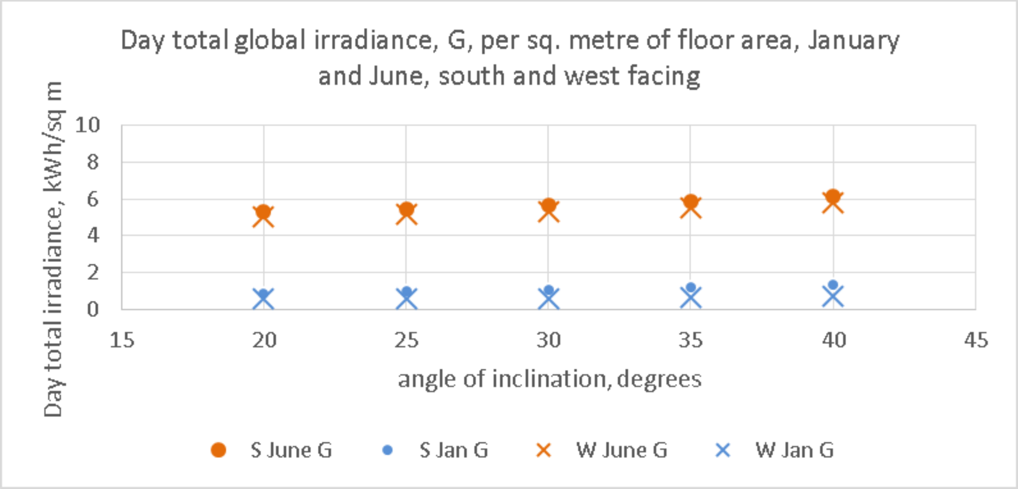


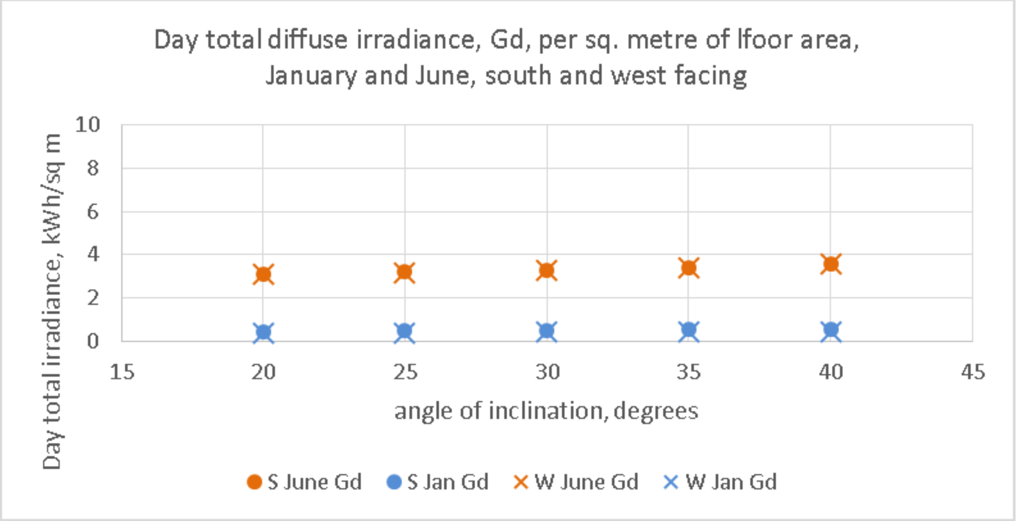
Day total diffuse irradiance, Gd, per sq. metre roof panel, January and June, south and west facing

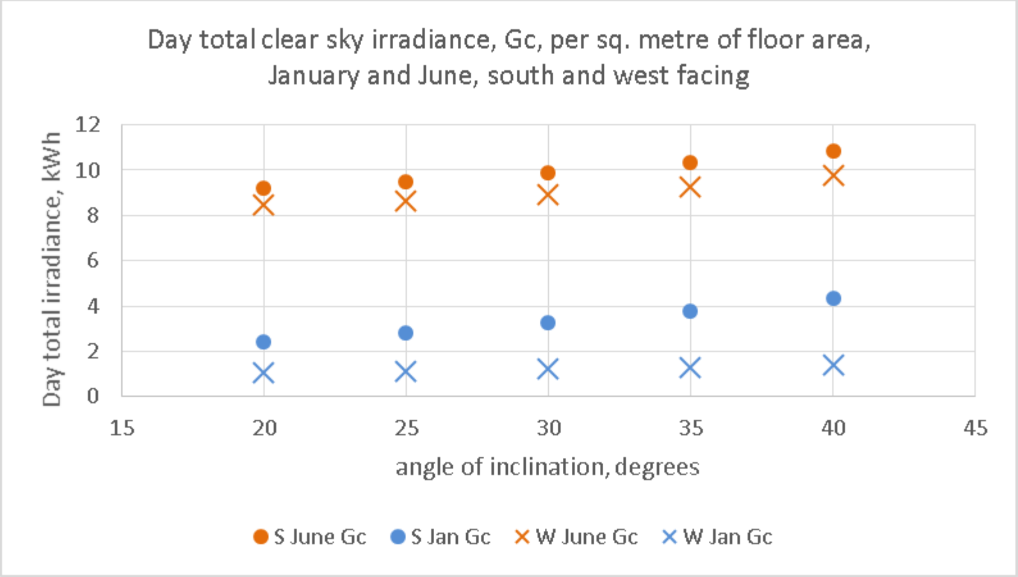


Day total clear sky irradiance, Gc, per sq. metre roof panel, January and June, south and west facing

Day total energy, per square metre of horizontal (floor area)

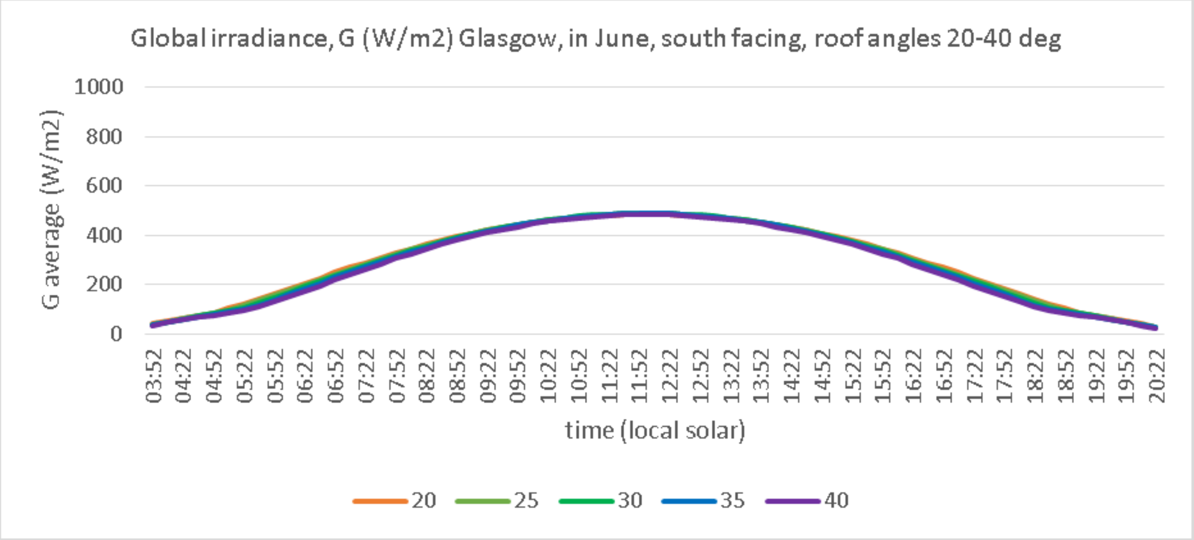


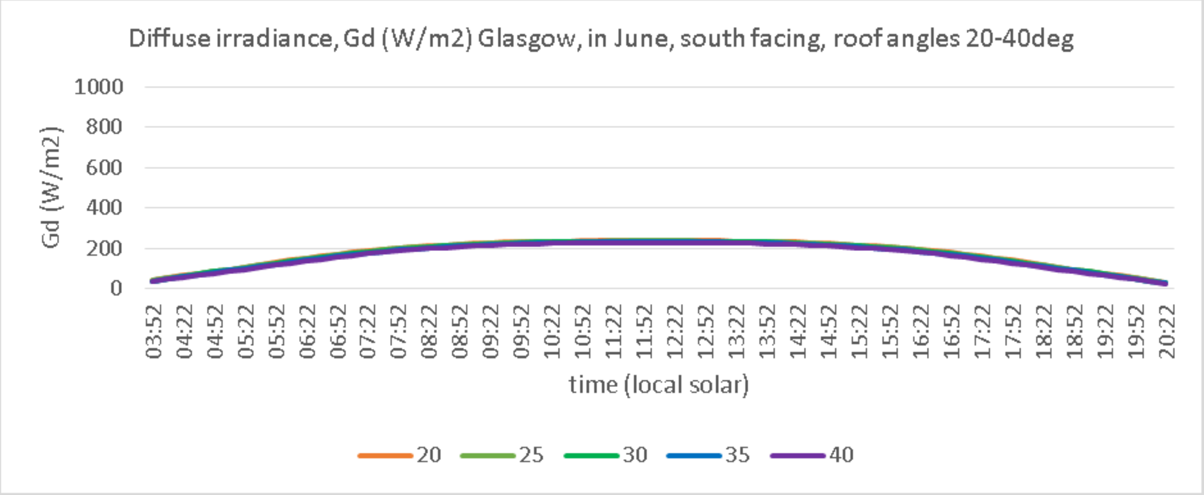


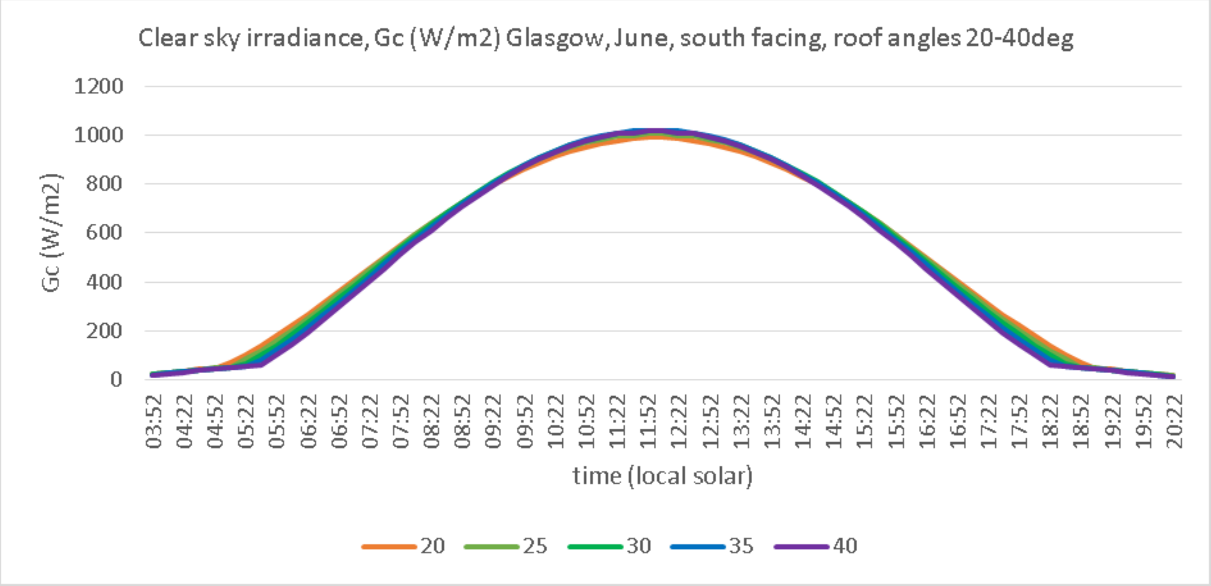


Solar irradiation during the day, per unit area of roof / inclined panel

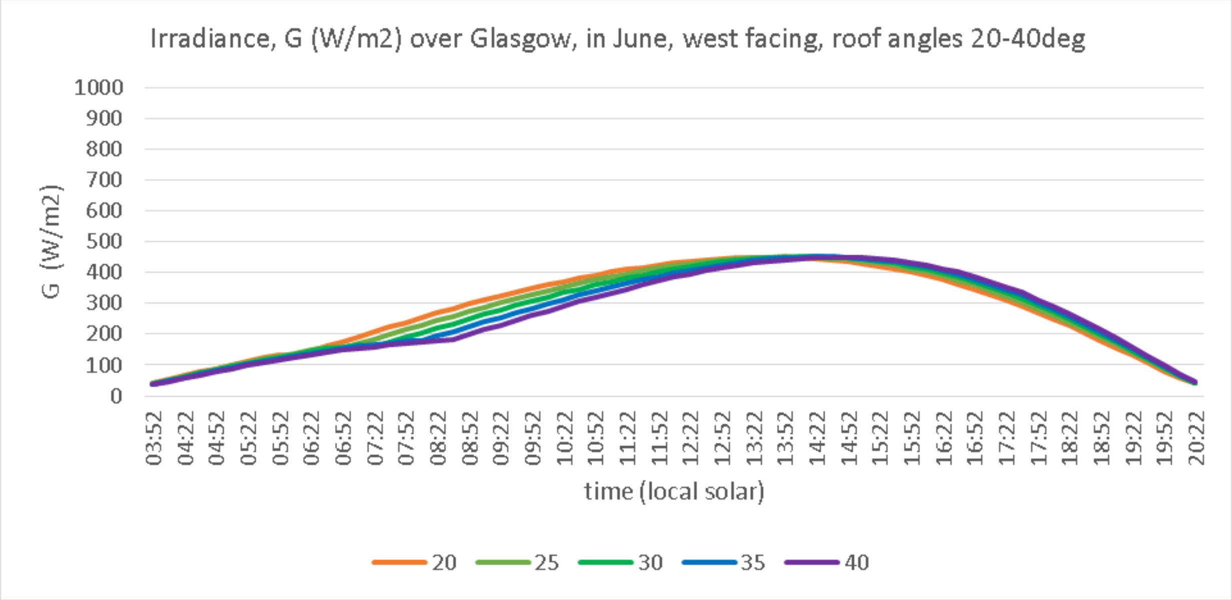
June, south facing, irradiance per unit area of roof

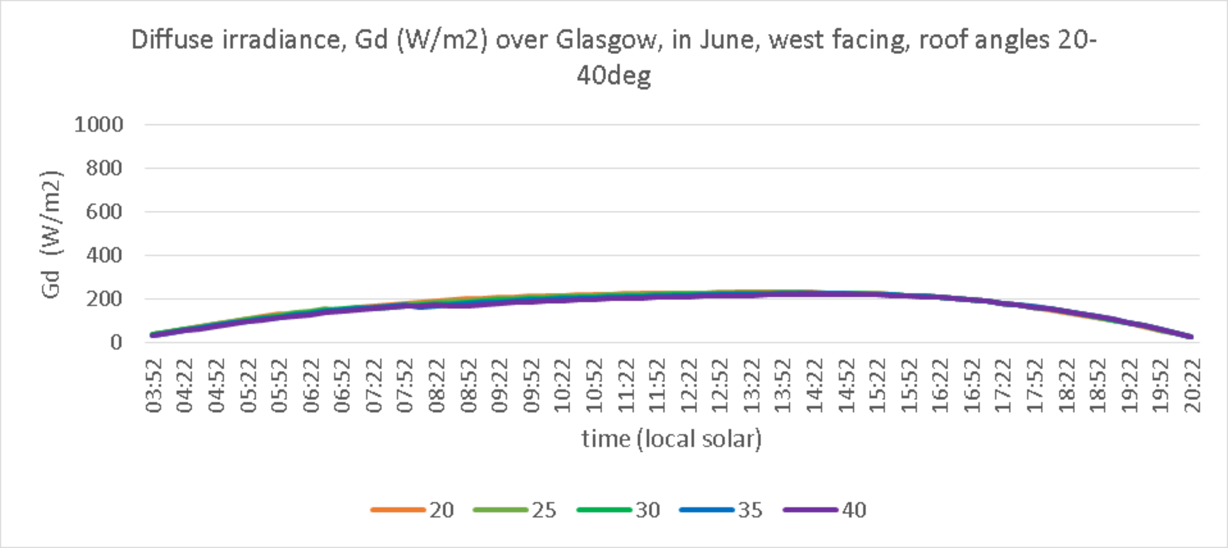


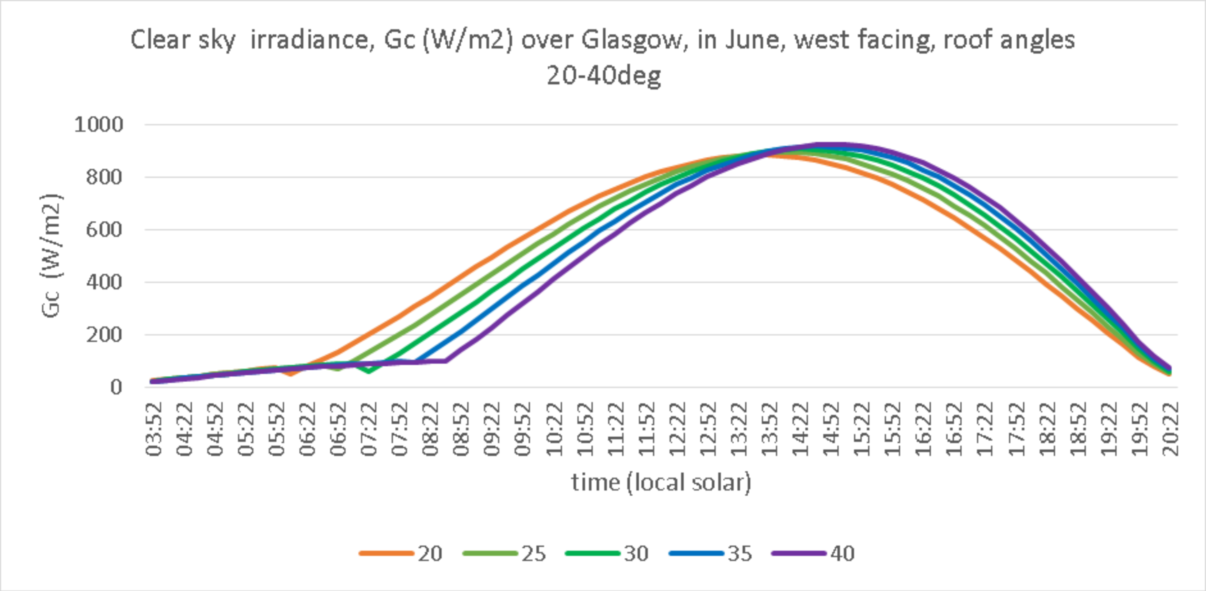




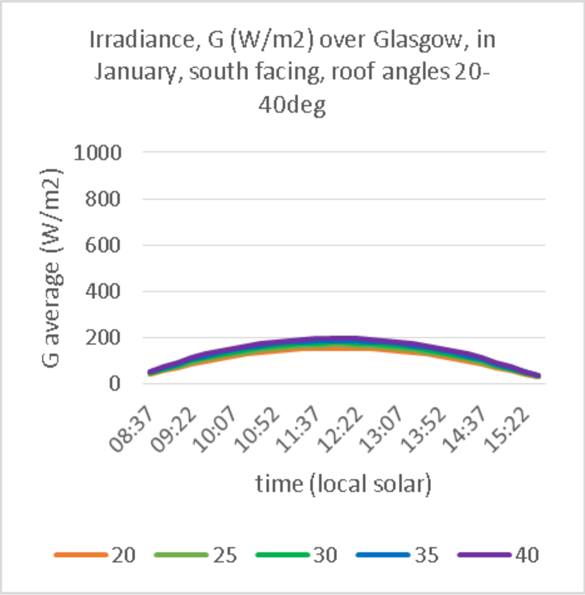
June, west facing, per unit area of roof

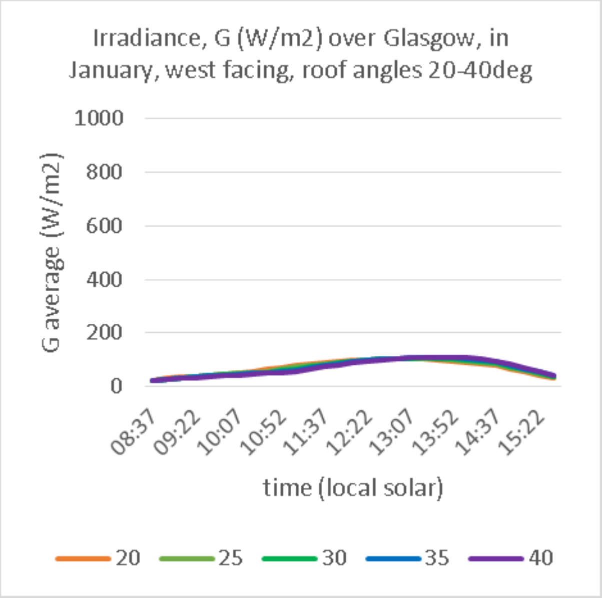


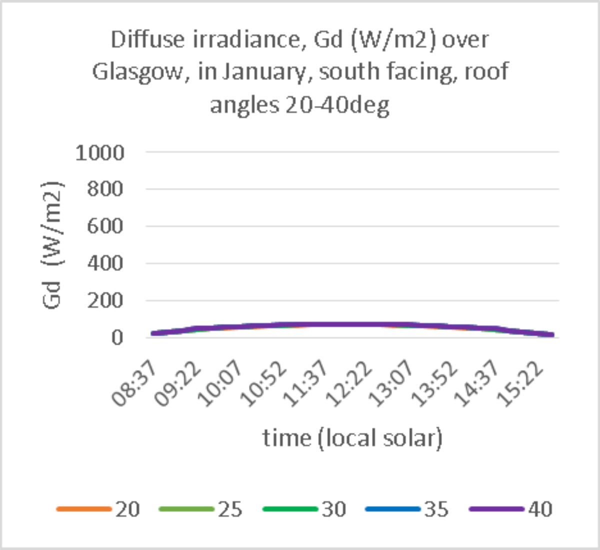


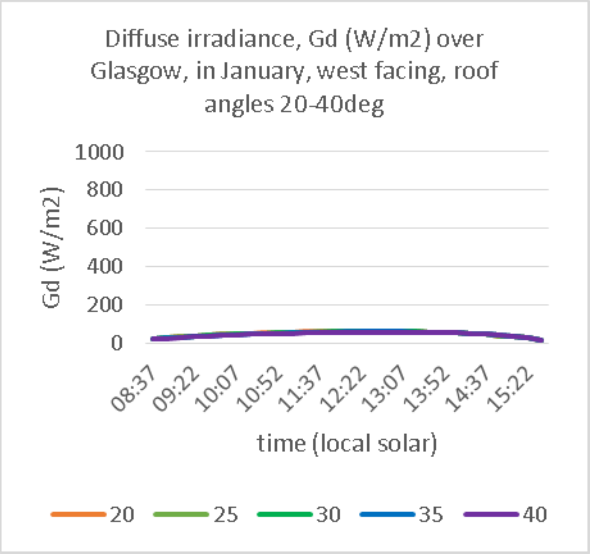


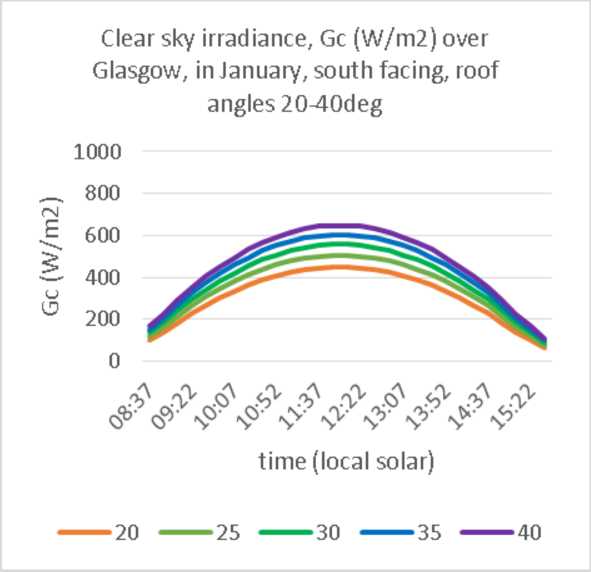
January, south and west facing, irradiance per unit area of roof

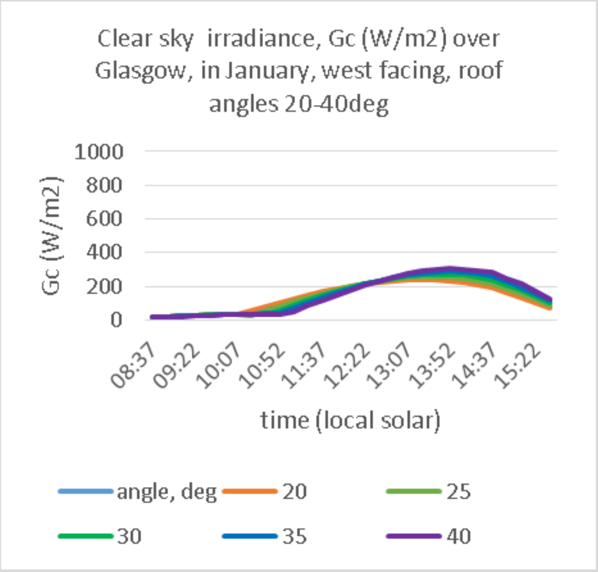

Irradiance, G (W/m2) over Glasgow, in January, south facing, roof angles 20-40deg


Irradiance, G (W/m2) over Glasgow, in January, west facing, roof angles 20-40deg


Diffuse irradiance, Gd (W/m2) over Glasgow, in January, south facing, roof angles 20-40deg

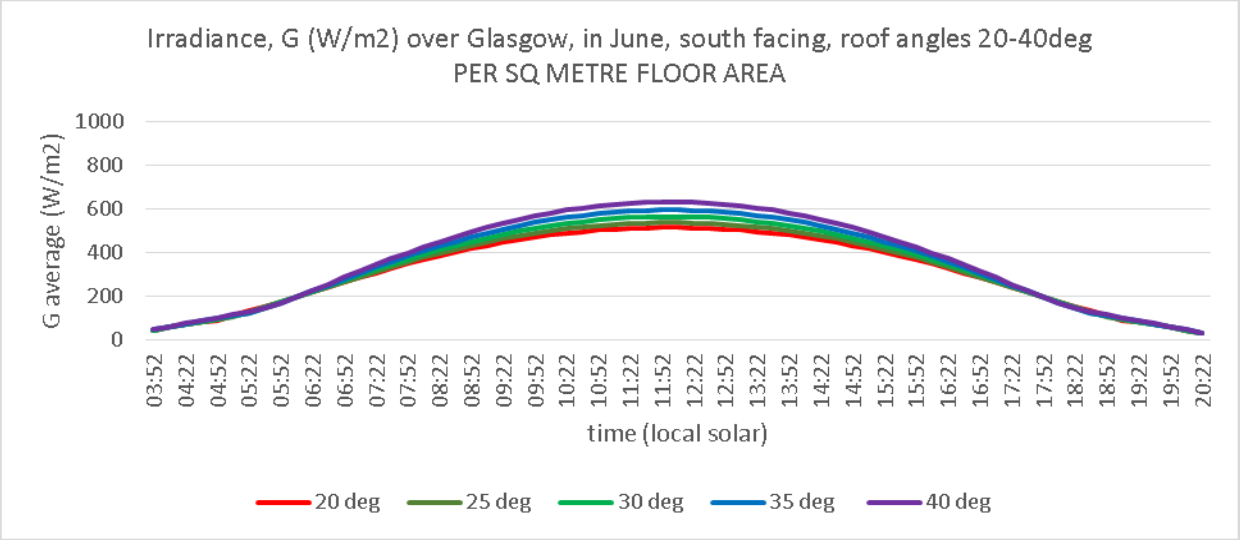

Diffuse irradiance, Gd (W/m2) over Glasgow, in January, west facing, roof angles 20-40deg

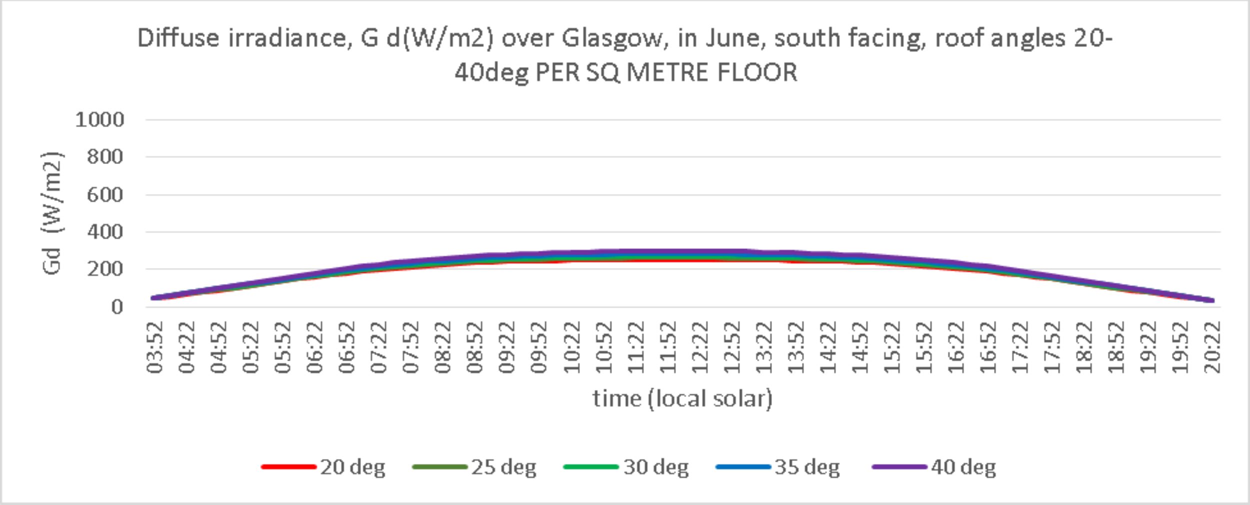

Clear sky irradiance, Gc (W/m2) over Glasgow, in January, south facing, roof angles 20-40deg

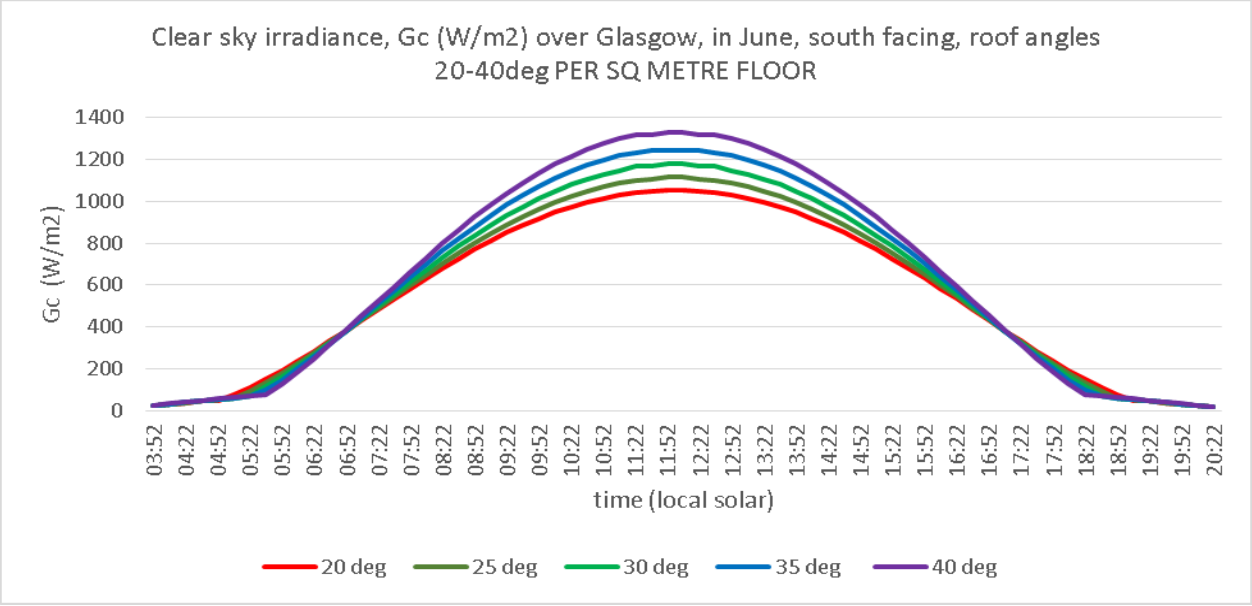

Clear sky irradiance, Gc (W/m2) over Glasgow, in January, west facing, roof angles 20-40deg

Solar irradiation during the day, per unit area of horizontal surface under inclined panel (floor area)

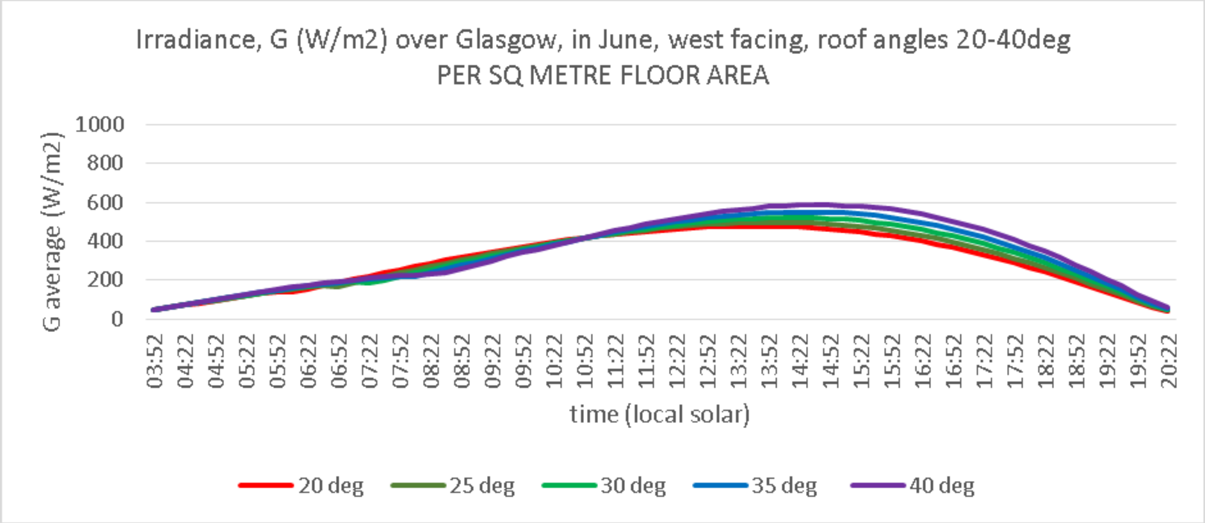
June, south facing, irradiance <u>per unit area of floor</u>

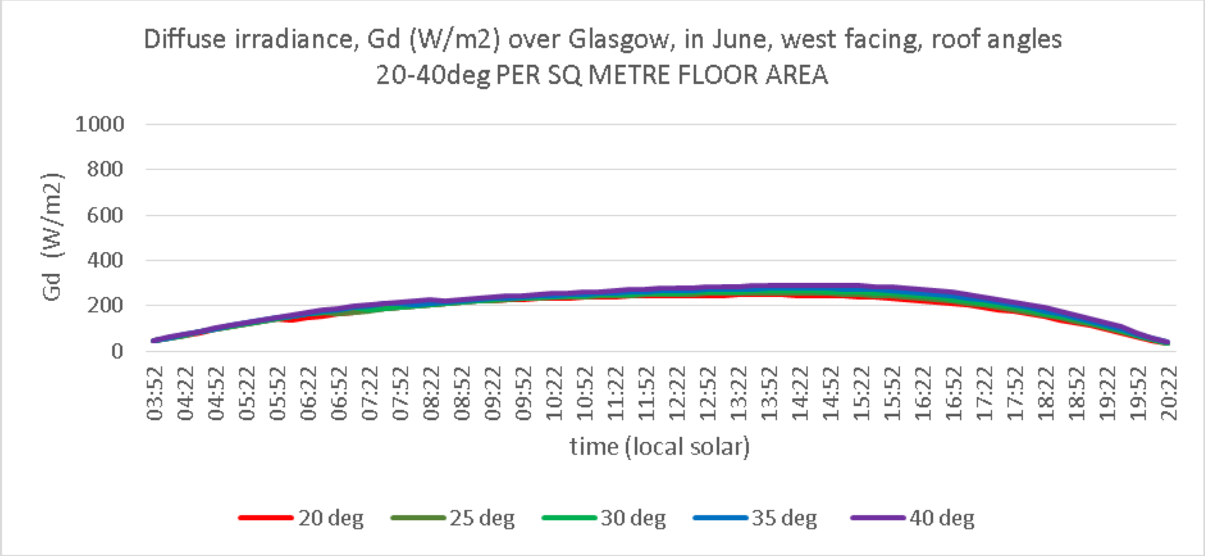


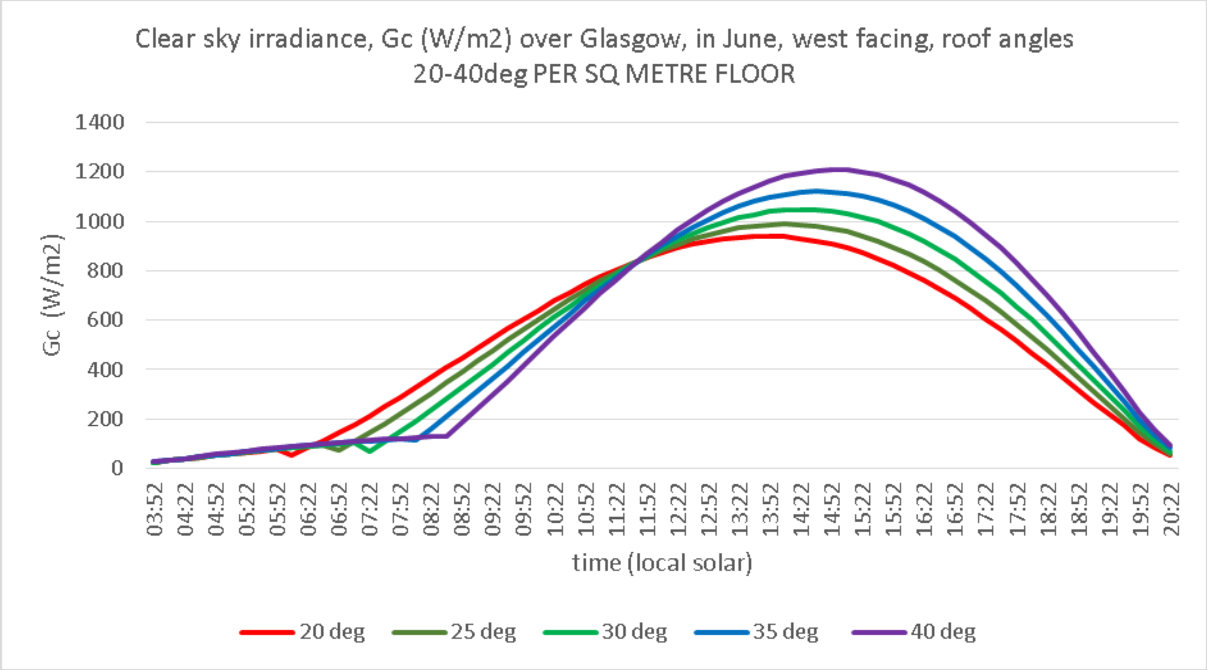




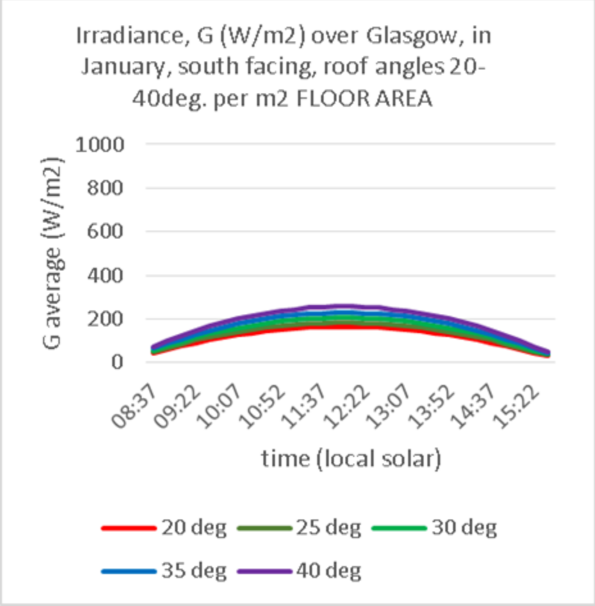
June, west-facing, irradiance <u>per unit area of floor</u>

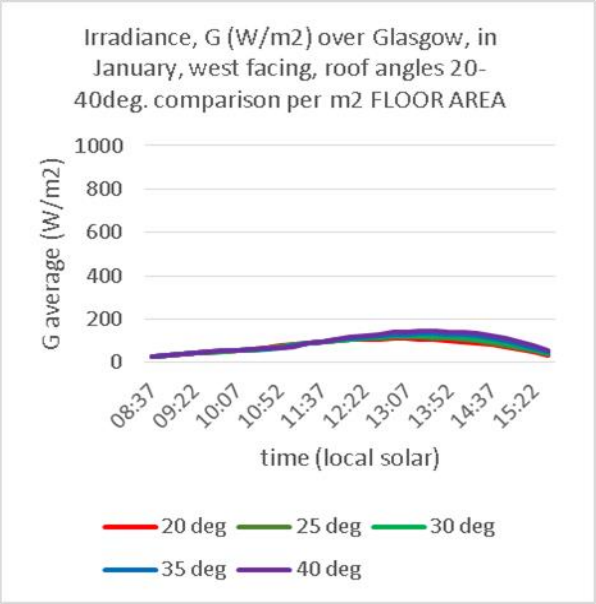


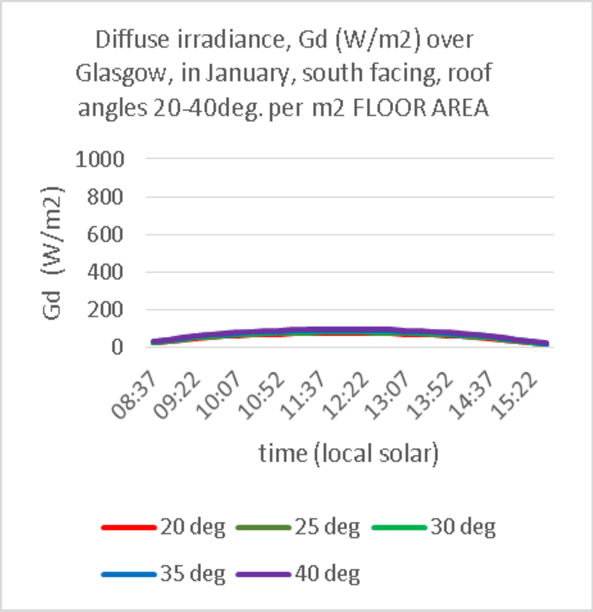


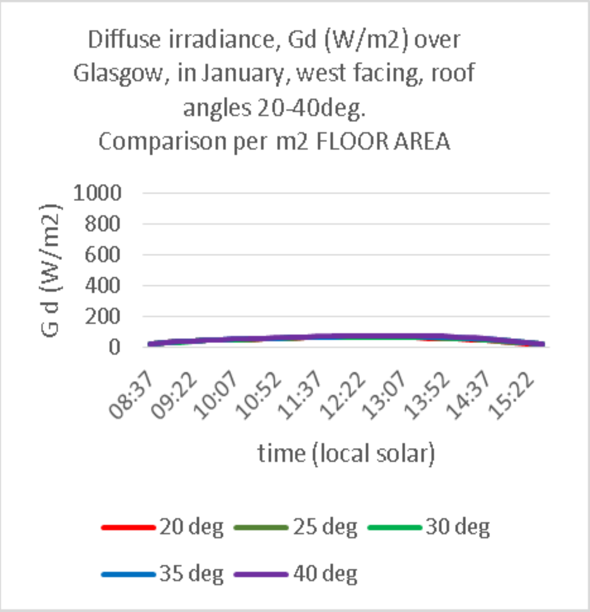


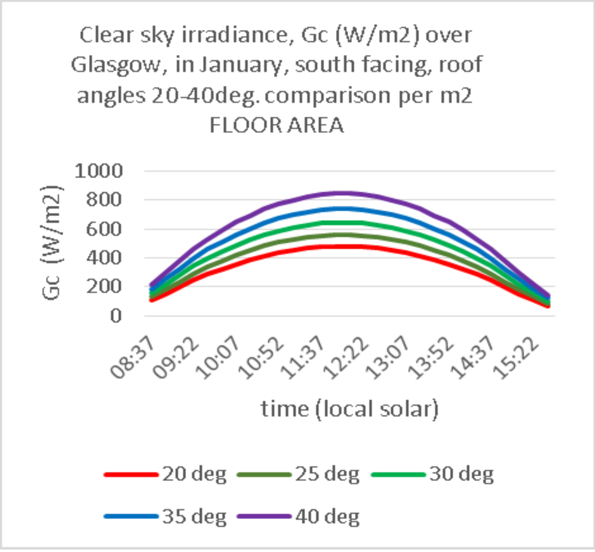
January, south & west facing, irradiance per unit area of floor

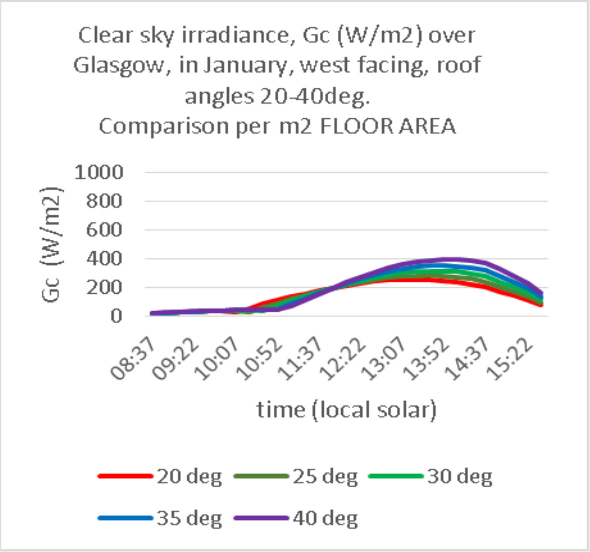

Irradiance, G (W/m2) over Glasgow, in January, south facing, roof angles 20-40deg. per m2 FLOOR AREA


Irradiance, G (W/m2) over Glasgow, in January, west facing, roof angles 20-40deg. comparison per m2 FLOOR AREA


Diffuse irradiance, Gd (W/m2) over Glasgow, in January, south facing, roof angles 20-40deg. per m2 FLOOR AREA


Diffuse irradiance, Gd (W/m2) over Glasgow, in January, west facing, roof angles 20-40deg.
Comparison per m2 FLOOR AREA


Clear sky irradiance, Gc (W/m2) over Glasgow, in January, south facing, roof angles 20-40deg. comparison per m2 FLOOR AREA


Clear sky irradiance, Gc (W/m2) over Glasgow, in January, west facing, roof angles 20-40deg.
Comparison per m2 FLOOR AREA

APPENDIX 4 EFFECT OF APPLIANCE OWNERSHIP, AND OCCUPANT NUMBERS, ON AGGREGATED ELECTRICAL DEMAND PATTERNS.

The profiles below are all from Richardson Model, 100 runs.

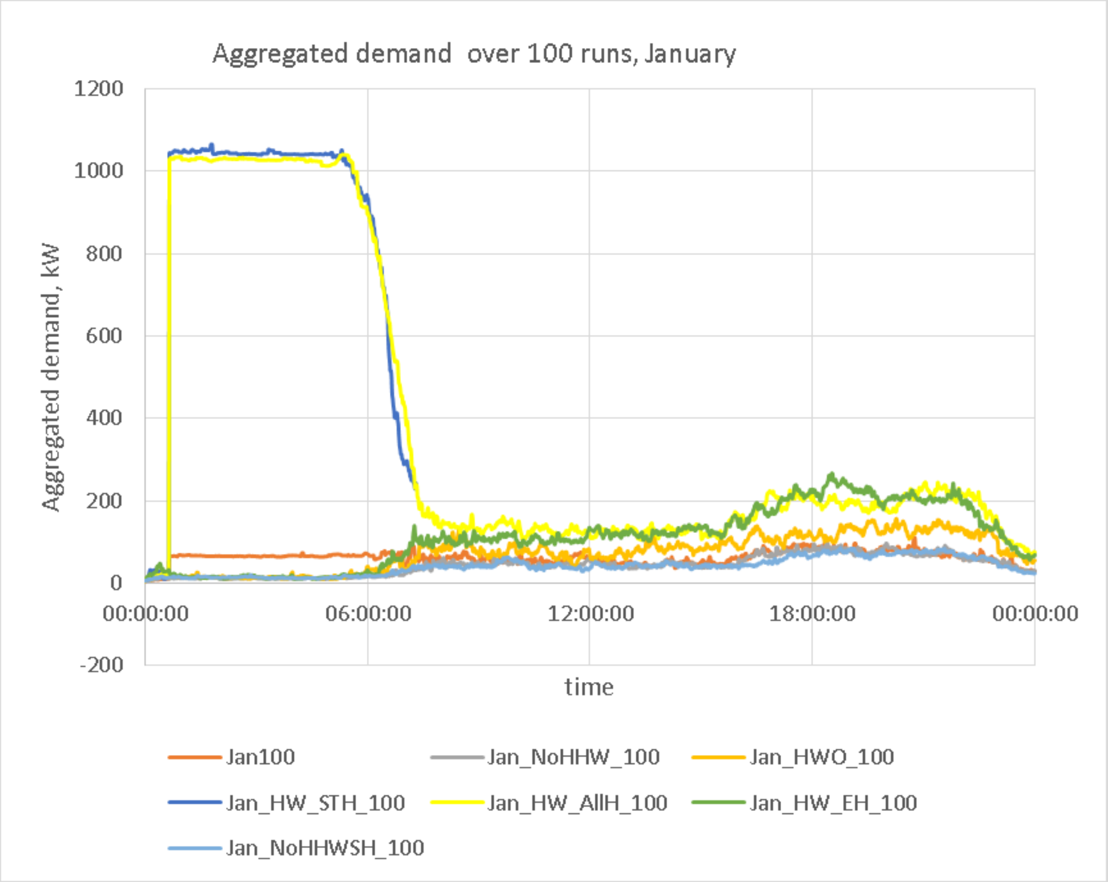
The effect of different appliance allocation (for water and space heating) on demand profiles

All appliances other than heating have Richardson model defaults unless otherwise stated.

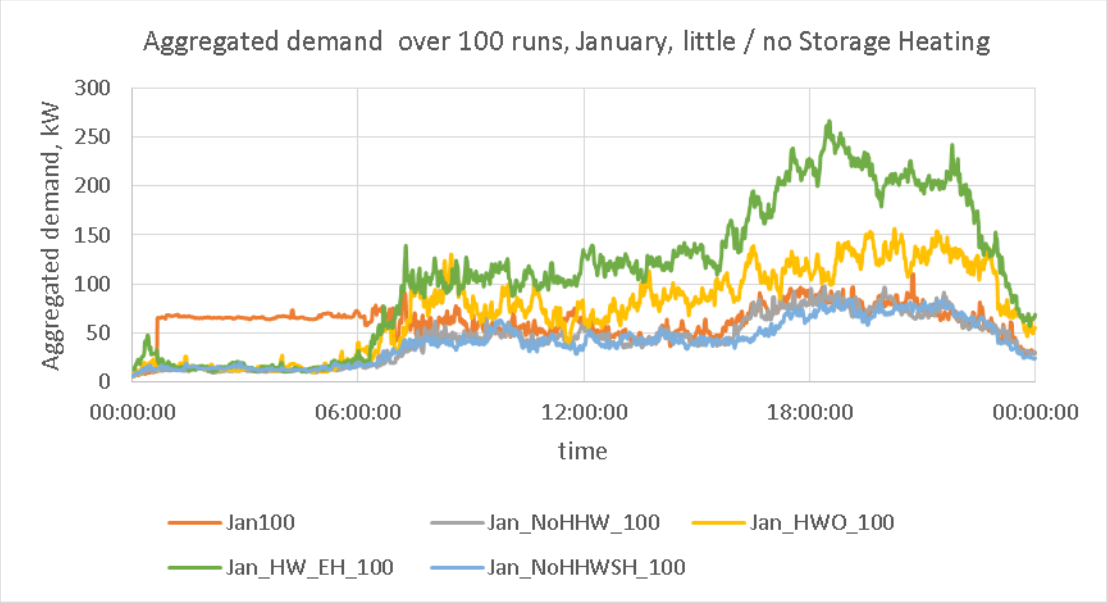
Key:

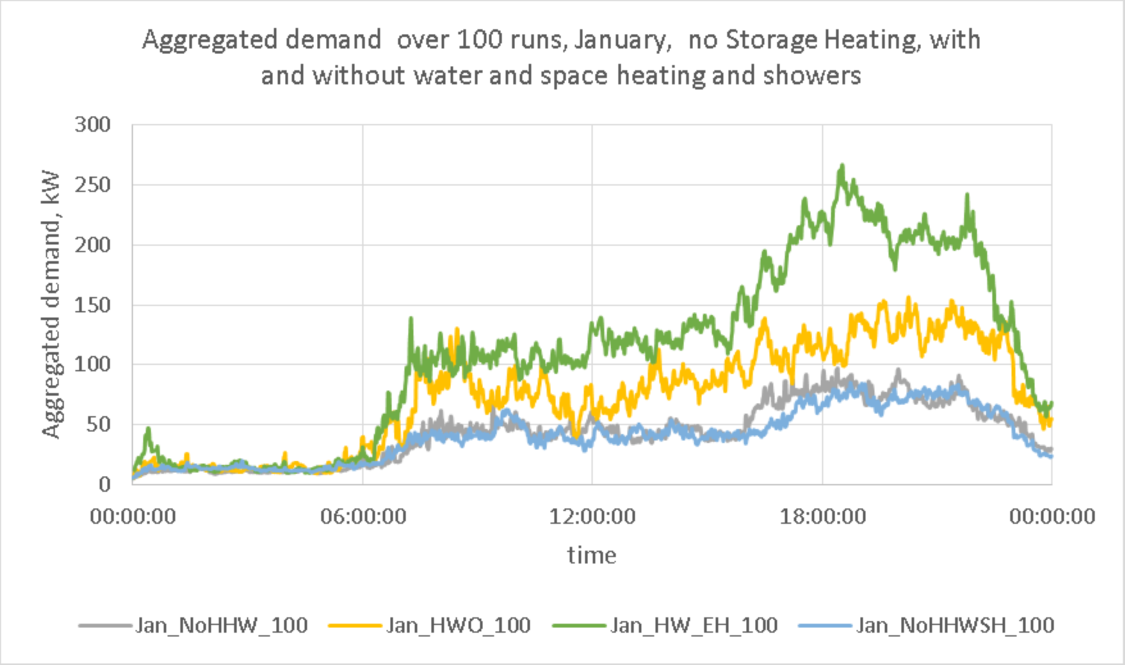
Legend	
Jan_...	For January
June_...	For June
_[no details]_100	100 runs, Richardson default settings
_HW_STH_100	100 runs, all have electric water and storage heating
_HW_AllH_100	100 runs, all have electric water, storage and other space heating
_HW_EH_100	100 runs, all have electric water and space heating but no storage heating
_HW_HWO_100	100 runs, all have electric water heating but not space heating
_NoHHW_100	100 runs, no electric heating or hot water
_NoHHWSH_100	100 runs, no electric heating, hot water, or showers

Figure 1 Aggregated demand profiles, January, with and without electric space and water heating, including 100% ownership of storage heating



Aggregated demand profiles, January, with and without electric space and water heating, but with little[1] or no storage heating





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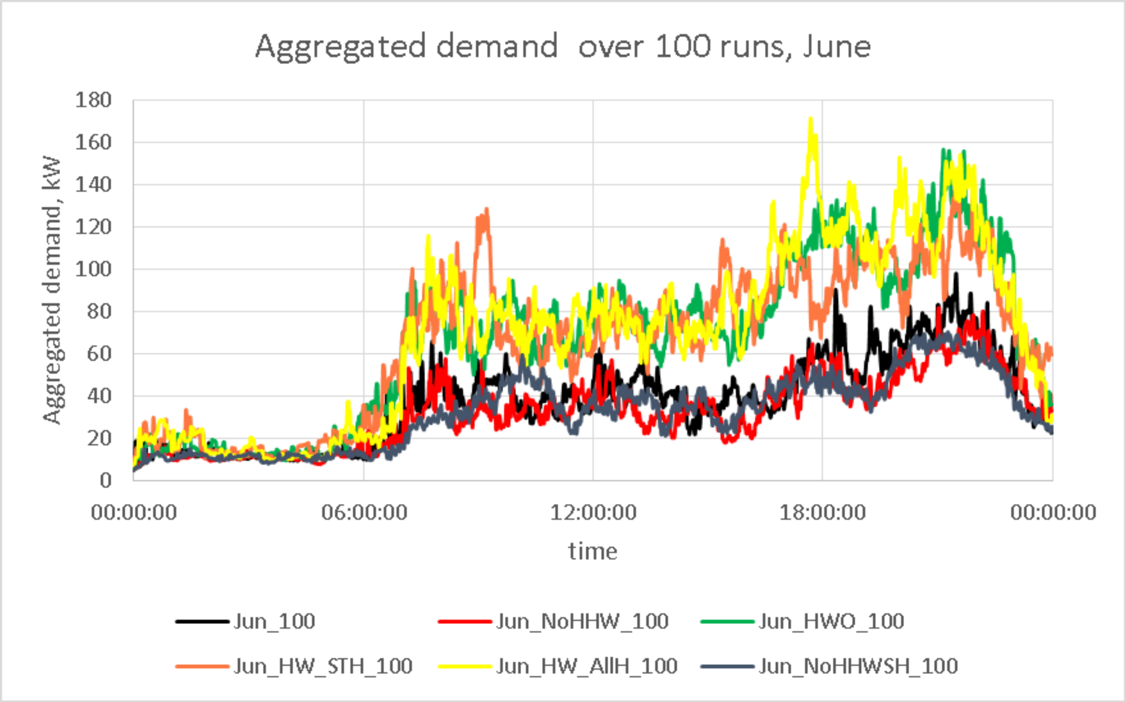
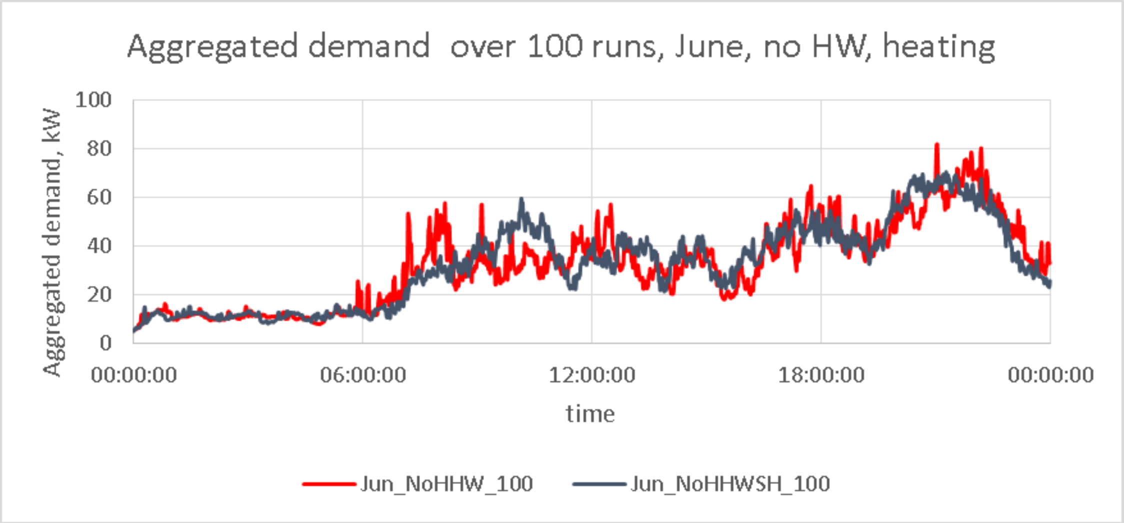
[1] “little” ownership of storage heating is the Richardson default value of 2.6% probability of ownership

Aggregated demand profiles, June, with and without electric space and water heating, including 100% ownership of storage heating



Aggregated demand profiles, June, without electric space and water heating, with and without electric showers



The effect of numbers of occupants on demand profiles, for urban scenarios (no electrical space or water heating) and rural scenarios (significant electrical water and space heating)

Some investigations were done on the effect of different numbers of occupants. One example, an urban scenario, with no electric space or water heating, is shown in Figure 2.

Figure 2 January, 100 runs. Urban scenario (no electric heating or hot water). Aggregated demand profile during the day, for different numbers of occupants

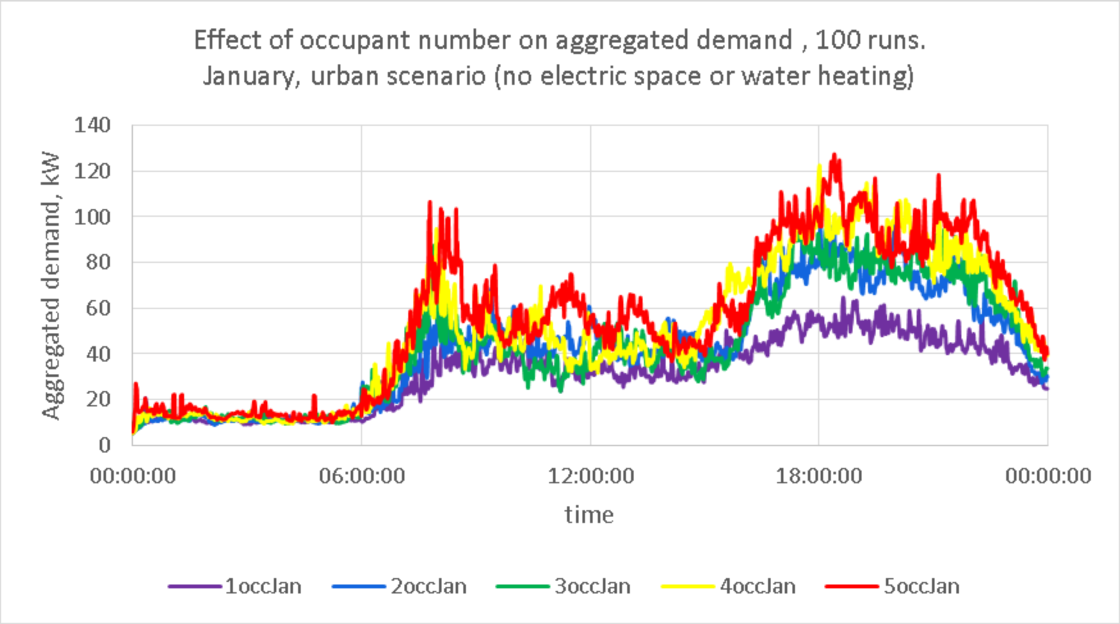
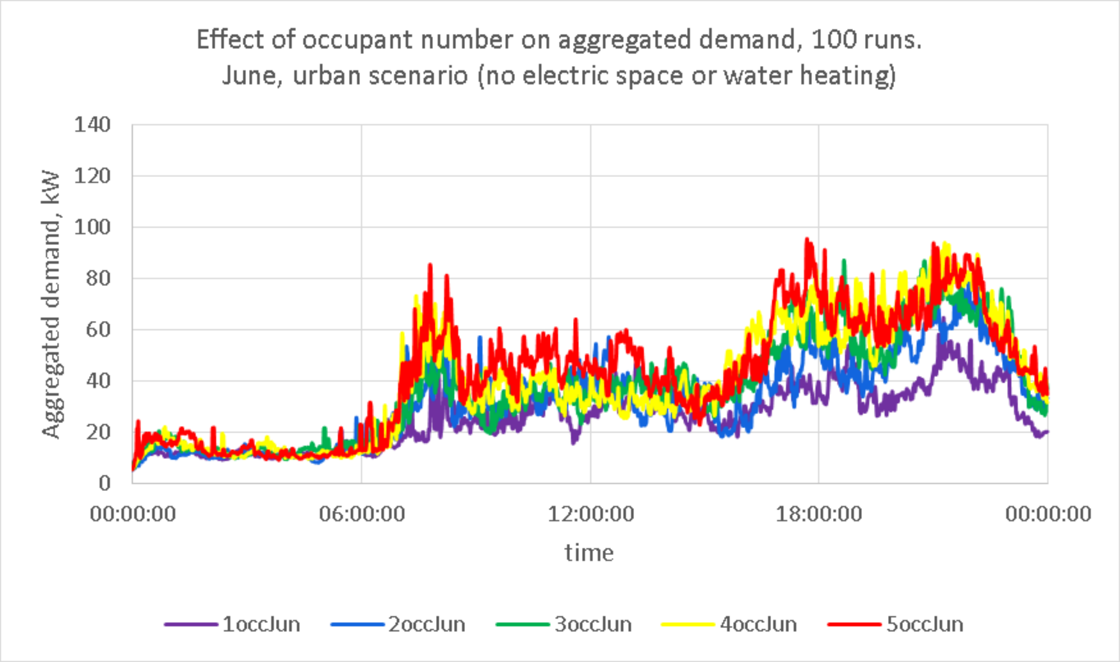


Figure 3 June, 100 runs. Urban (no electric heating or hot water). Aggregated demand profile during the day, for different numbers of occupants



Two scenarios were devised, with mixed numbers of occupants: “Balindalloch” (three-bedroom flats) and “Onslow” (two-bedroom flats). Proportions of households with occupant numbers are reproduced here.

(Table 7 in main report)

No. of occupants in household	**% of households**		
	Urban		**Rural**
	Ballindalloch	**Onslow**	
1	6	30	30
2	48	54	20
3	30	12	20
4	8	4	20
5	8	0	10

Figure 4 January and June, mixed numbers of occupants, “Ballindalloch” scenario

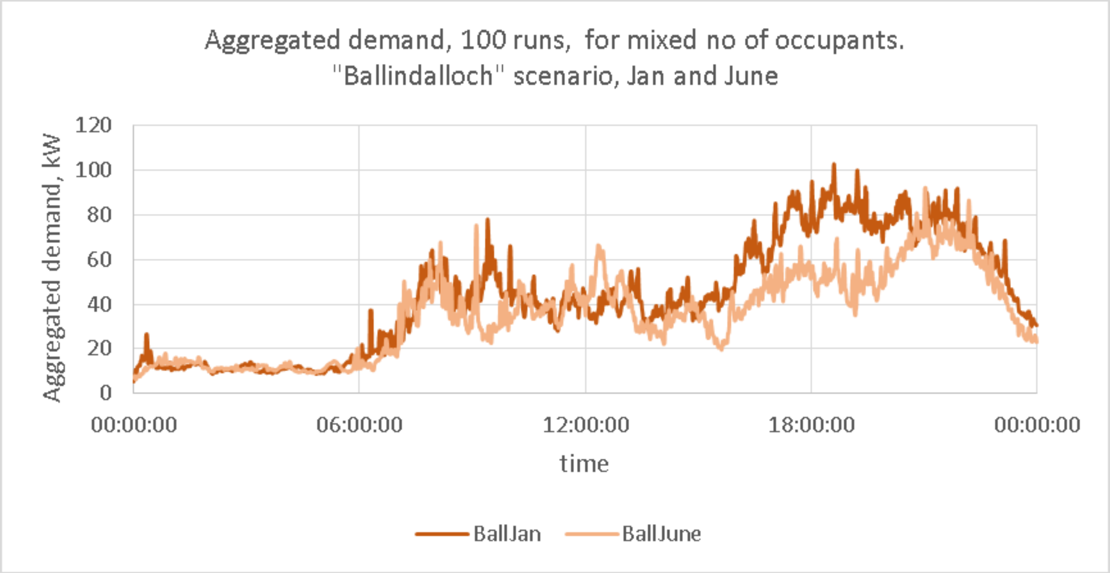
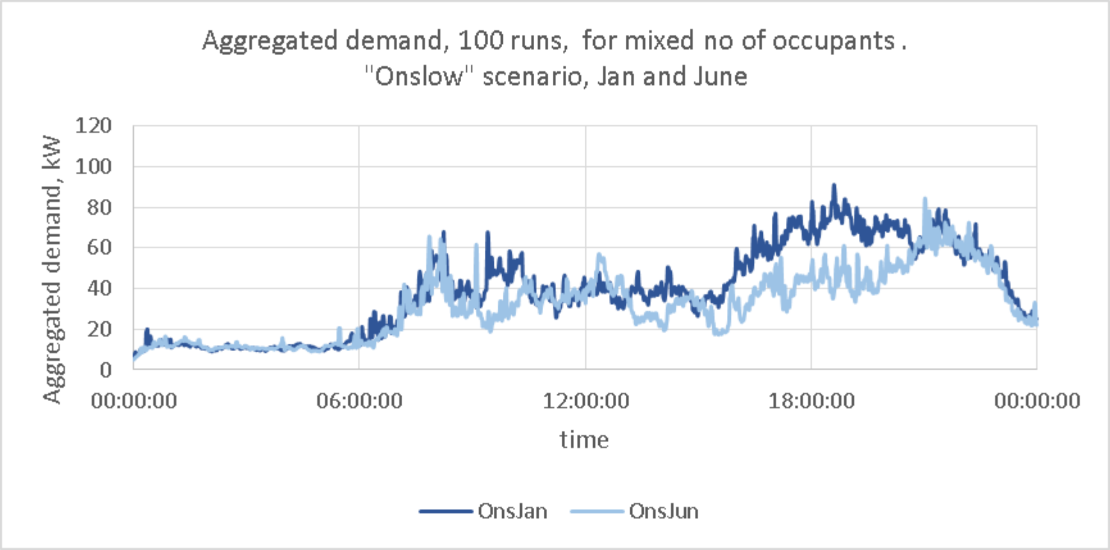


Figure 5 January and June, mixed numbers of occupants, “Onslow” scenario



Similar investigations were done on rural scenarios, which include significant electrical space and water heating (details of which are in Table 7 in the main report).

Figure 6 January, 100 runs. Rural scenario (significant electric space and water heating). Aggregated demand profile during the day, for different numbers of occupants

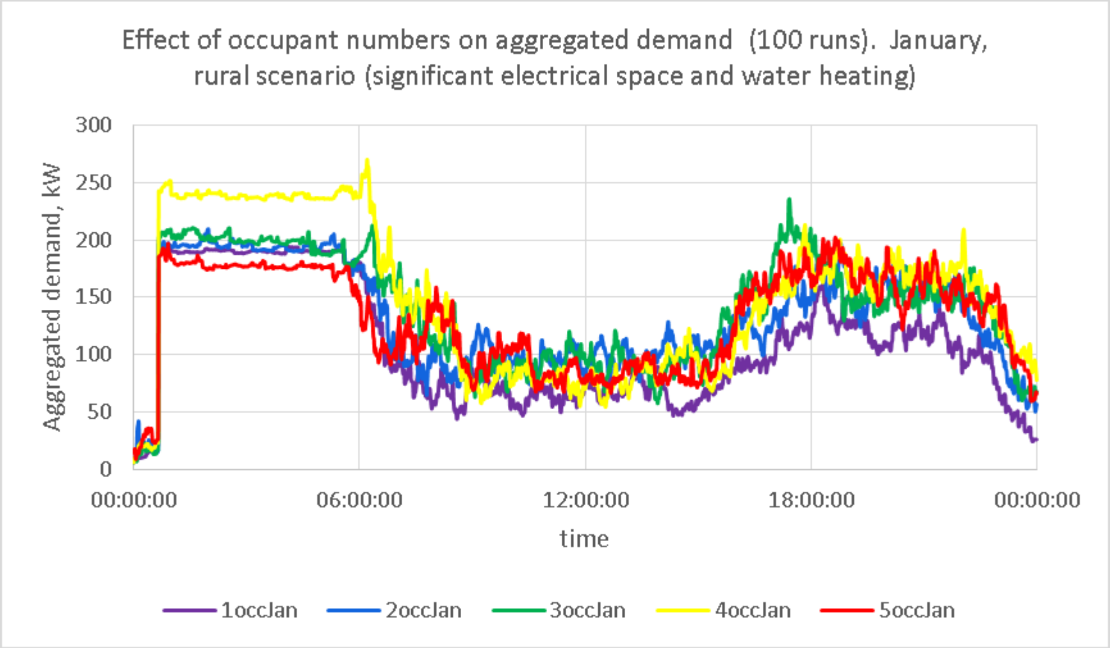
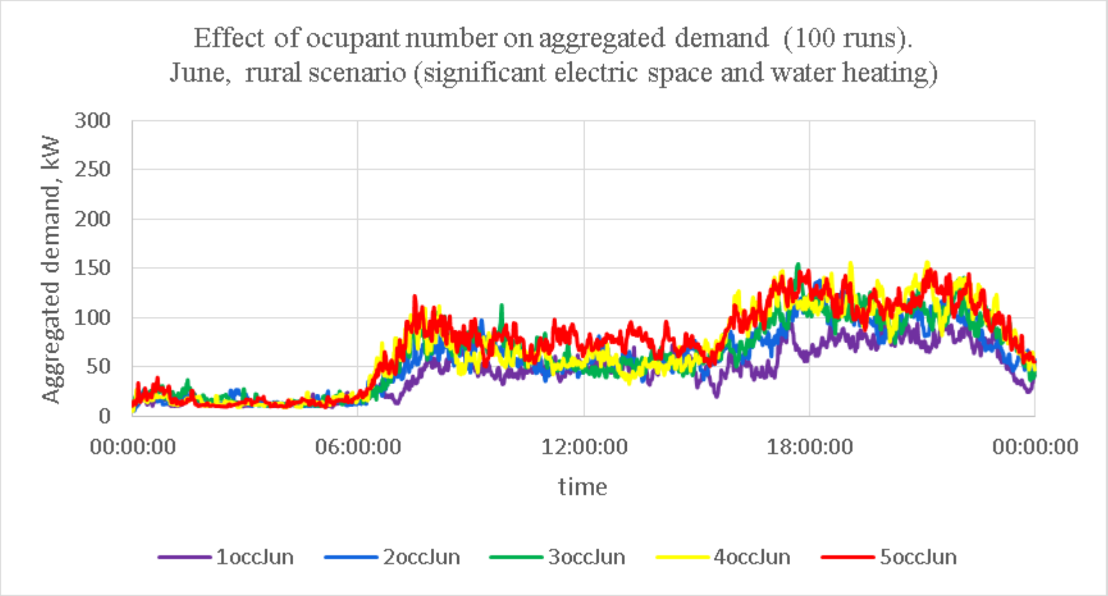


Figure 7 June, 100 runs. Rural (some electric space and water heating). Aggregated demand profile during the day, for different numbers of occupants



Two scenarios were devised:

Rural 1: the above appliance ownership, and mixed numbers of occupants (Table 7 & 8 in main report).

Rural 2. As for rural 1, but with no storage heating ownership. This makes no difference in June, so this was only done for January.

The aggregated demand patterns are displayed in Figure 8 and Figure 9 below.

Figure 8 January and June, mixed numbers of occupants, "Rural 1" scenario

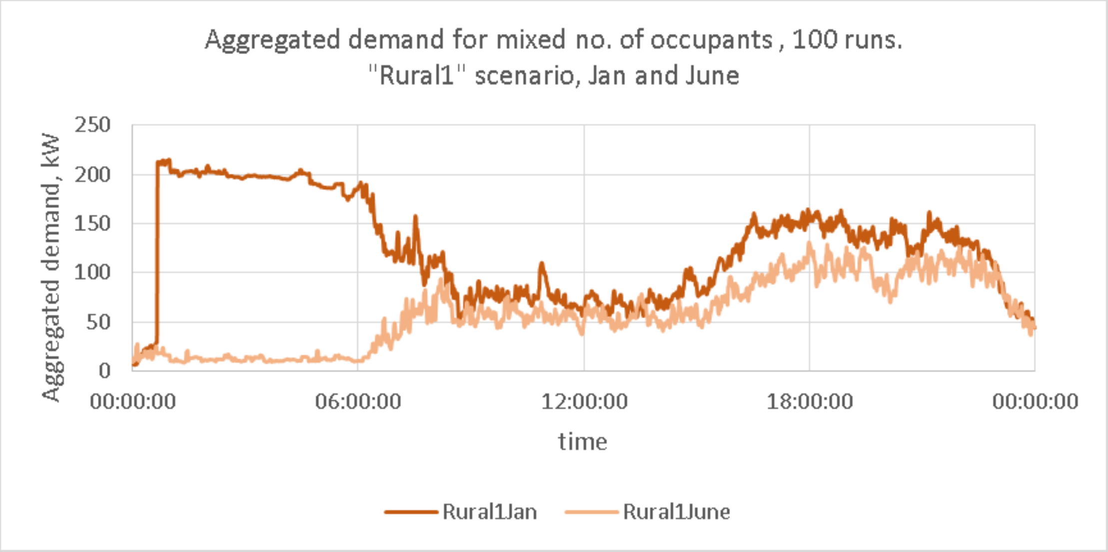
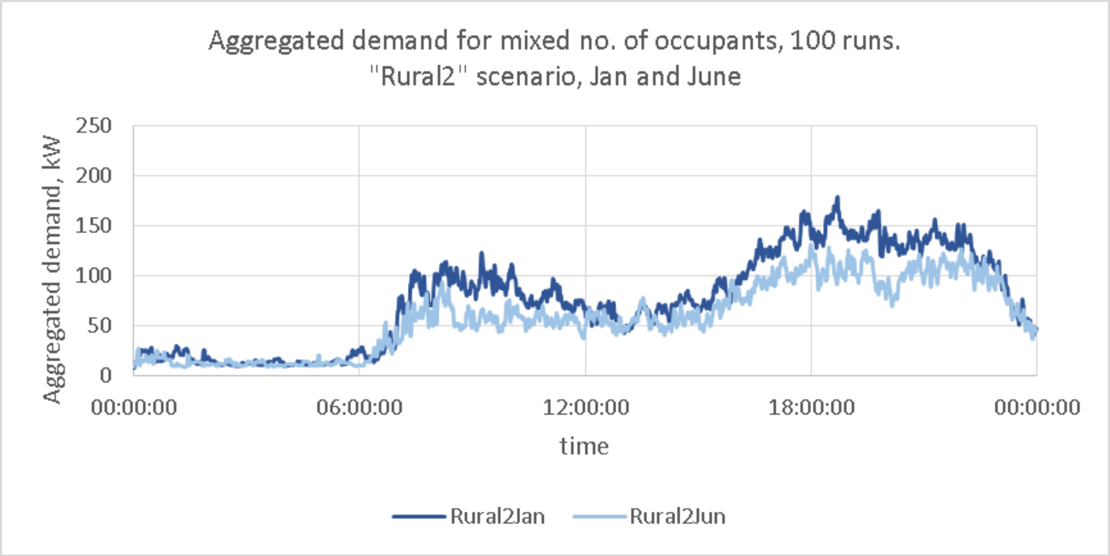


Figure 9 January and June, mixed numbers of occupants, "Rural 2" scenario


Aggregated demand for mixed no. of occupants, 100 runs.
"Rural2" scenario, Jan and June
Aggregated demand, kW
250
200
150
100
50
0
00:00:00
06:00:00
12:00:00
18:00:00
00:00:00
time
Rural2Jan
Rural2Jun

APPENDIX 5 FURTHER INFORMATION ON DEMAND PROFILES FOR SIX RUNS, BALLINDALLOCH SCENARIO

Composition of the above datasets: numbers of households of different numbers

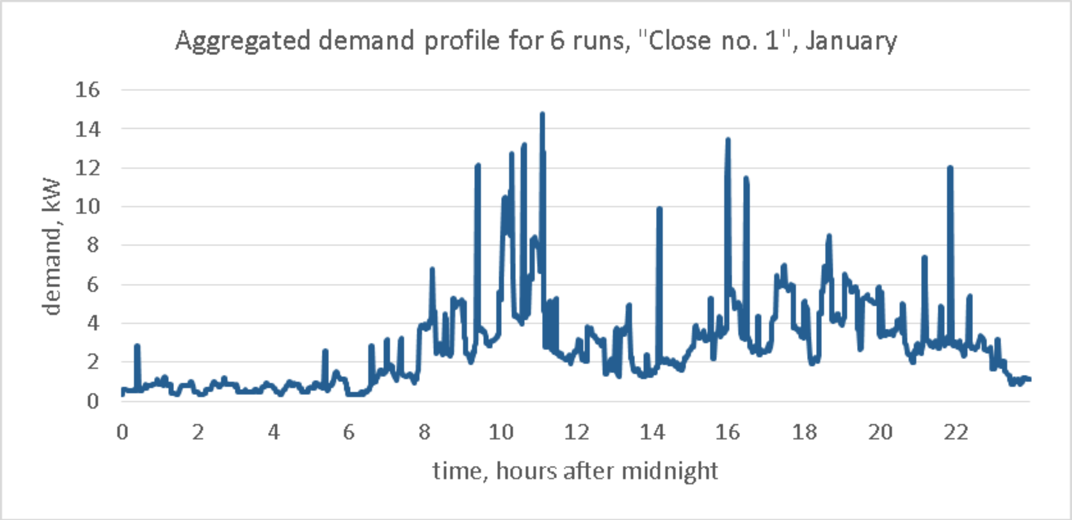
January

Close number	Number of households of following number of occupants					Total number of households
	1	2	3	4	5	
1	0	3	2	1	0	**6**
2	0	3	3	0	0	**6**
3	0	3	1	1	1	**6**
4	1	3	1	1	0	**6**

June

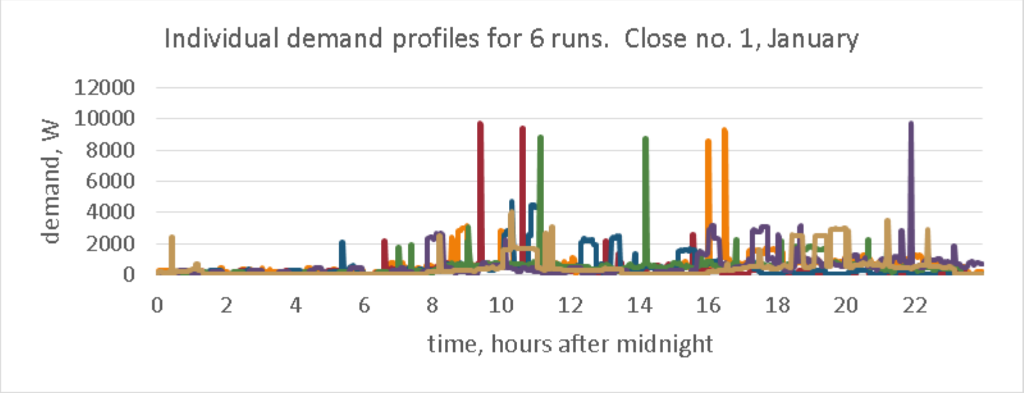
Close number	Number of households of following number of occupants					Total number of households
	1	2	3	4	5	
1	0	3	2	1	0	**6**
2	0	3	3	0	0	**6**
3	0	3	1	1	1	**6**
4	1	3	1	0	1	**6**

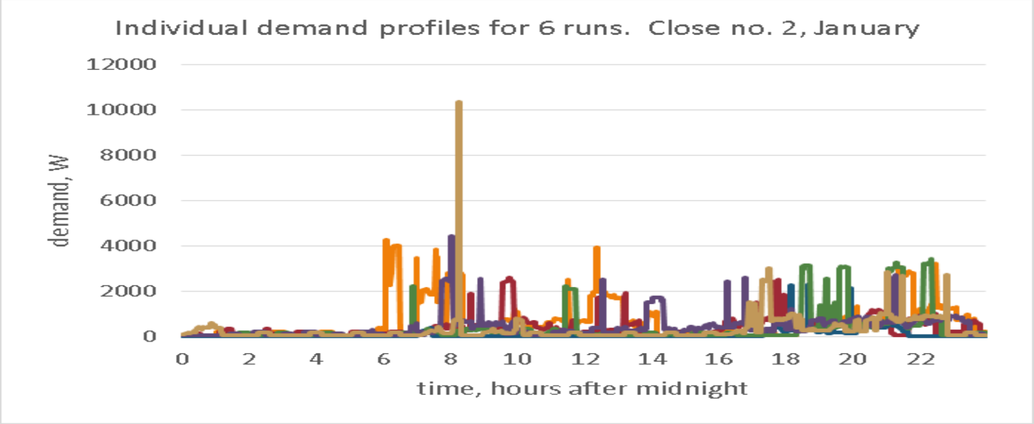
An aggregated demand profile for one of the runs ("close no.1") in January, is shown below.

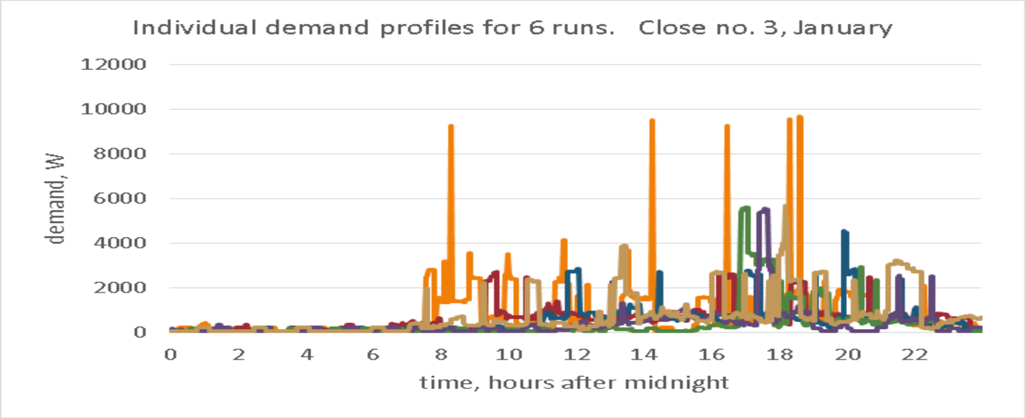


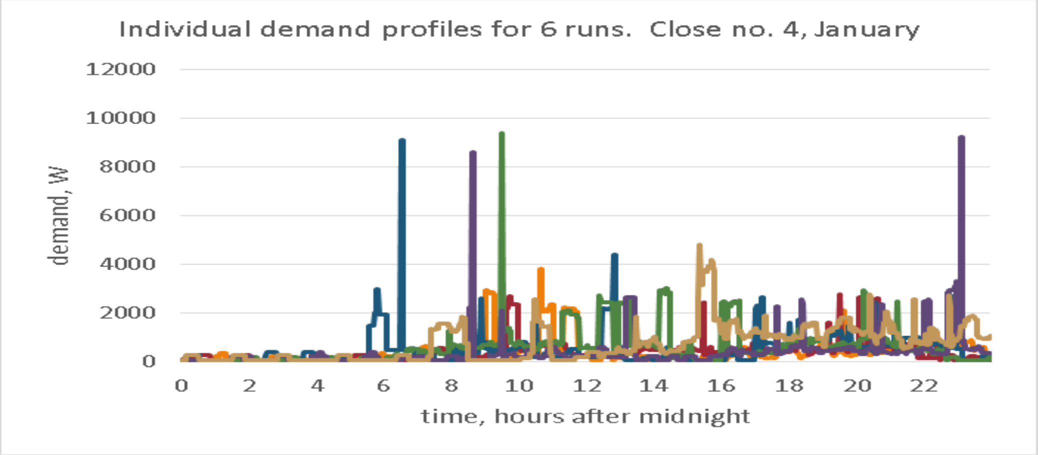
Individual demand profiles for groups of six runs, in January shown on next page.

Individual demand profiles for groups of six runs, Ballindalloch scenario, January









APPENDIX 6 CALCULATION: READING SOLAR DATA FROM PVGIS. AN EXAMPLE MATHCAD SHEET: JANUARY (NO TIME CORRECTION).

Reading solar data from PVGIS

1. Inserting a component into Mathcad that has time and solar irradiation data

This file reads outputs from PVGIS (here: G, Gd and Gc) at the timesteps on PVGIS, and puts these in a format to be used by the "calculation" Mathcad sheet.

PVGIS define:	G	- global irradiance on a fixed plane (W/m2)
	Gd	- diffuse irradiance on a fixed plane (W/m2)
	Gc	- global clear-sky irradiance on a fixed plane (W/m2)

First, PVGIS is run, using "Glasgow" as a location. In PVGIS, inputting "Glasgow" gives coordinates 55.864 latitude, -4.252 longitude, or 55 deg 51' 51" North and 4 deg 15 ' 6" West. The "text file" output option is selected.

An example of a text file output for January, south facing, roof angle 35 degrees, is used, and appended in Appendix 1.

The text file output from the PVGIS run is manually copied into an Excel workbook.

Then a blank column in the Excel workbook is used to calculate a "minutenumber" - number of minutes elapsed since midnight - from the 24hr time listed in the PVGIS data. This is done using the Excel function HOUR and MINUTE. (e.g. in January, the first time at which there are data is 8:37AM, and the corresponding first "minute number" is calculated (in Excel) to be 517.) Blank columns between data are deleted.

This Excel file is named according to PVG - orientation - angle.

For example, output from a south-facing, 35 degree, is in a file called "PVGS35".

The month is in the name of the worksheet within the file: e.g. January output is in a worksheet "JanS35", and the June output is in a worksheet "JunS35".

An extract from this Excel worksheet is now inserted into this Mathcad workbook (using Insert - Component - Excel sheet). The insertion instructions include:

Outputs:0; Inputs: 1 - which sheet in the Excel file to read, and which row and column of the sheet to start and end with. The inserted component is instructed (manually) to only read rows populated with data, and to read columns of "minute number", "G", "Gd" and "Gc". The component is given the same name as the Excel sheet (no file extension).

PVGS35 :=

Worksheet

PVGS35 =

	0	1	2	3
0	517	54	26	151
1	532	71	34	206
2	547	89	42	265
3	562	107	50	326
4	577	121	55	374
5	592	134	59	...

Displaying part of this component

(Opening in Mathcad allows one to scroll down the table to read all data points.)

"Minuteno" is defined as a vector, populated with the first column of data in the component PVGS35. (Row and column numbers start at zero unless otherwise assigned).

$$\mathrm{minuteno} := \mathrm{PVGS35}^{\langle 0 \rangle}$$

Irradiation G, Gd and Gc are vectors, populated with the following columns, respectively:

$$\mathrm{solarG} := \mathrm{PVGS35}^{\langle 1 \rangle}$$

$$\mathrm{solarGd} := \mathrm{PVGS35}^{\langle 2 \rangle}$$

$$\mathrm{solarGc} := \mathrm{PVGS35}^{\langle 3 \rangle}$$

Displaying these readings in tables and in a graph:

minuteno =

	0
0	517
1	532
2	547
3	562
4	577
5	592
6	607
7	...

solarG =

	0
0	54
1	71
2	89
3	107
4	121
5	134
6	146
7	...

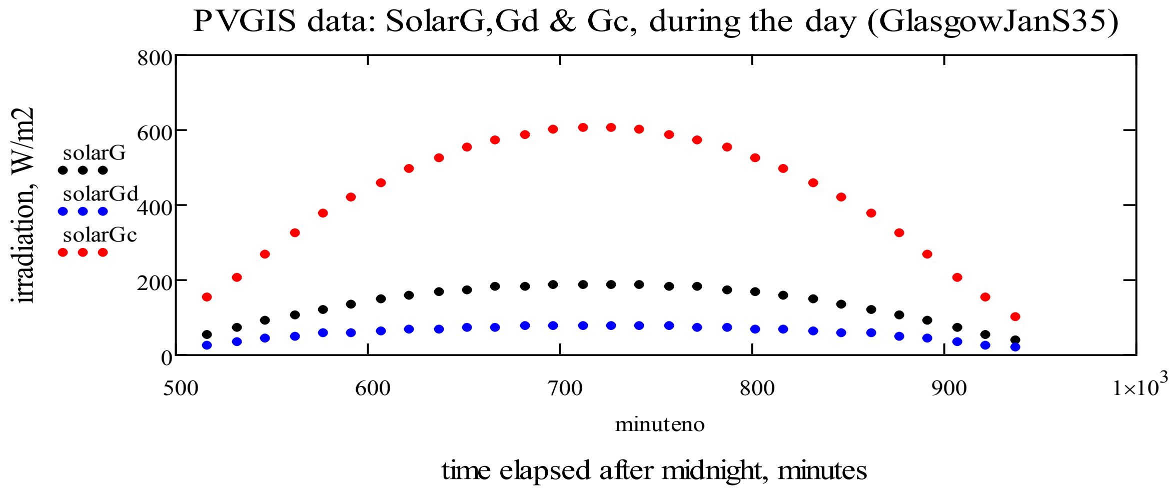
solarGd =

	0
0	26
1	34
2	42
3	50
4	55
5	59
6	63
7	...

solarGc =

	0
0	151
1	206
2	265
3	326
4	374
5	419
6	459
7	...

Maximum values are shown:- max(minuteno) = 937 max(solarG) = 188 max(solarGd) = 75 max(solarGc) = 604



2. Filling in "gaps" in PVGIS data

Interpolating data to calculate G,Gd,Gc at one-minute intervals, and inserting "zero" irradiation values before dawn and after dusk

Background

PVGIS lists data at 15 minute intervals.

As demand data at one-minute intervals will be used, it is necessary to calculate G, Gd, and Gc at one-minute intervals. The linear interpolation function in Mathcad is used.

PVGIS does not list any data during the night. Thus values (of zero) need to be assigned to irradiation during the night.

Calculation

The number of data points in each vector is counted by "length(vectorname)="

$\mathrm{length(minuteno)} = 29$

This is displaying the number of data points in "minuteno", i.e. the number of 15 minute time-steps at which there are data. (This example is in winter. At other times of year, when days are longer, the vector will have more data points.)

$\mathrm{dawn\_t} := \mathrm{minuteno}_0$

"dawn time" is defined as the first reading of "minuteno", i.e. the earliest time in the day at which there are data.

$\mathrm{dawn\_t} = 517$

Displaying "dawn_t"

$\mathrm{dusk\_t} := \mathrm{minuteno}_{\mathrm{length(minuteno)}-1}$

"dusk time" is the last reading of "minuteno", i.e. the latest time in the day at which there are data.

$\mathrm{dusk\_t} = 937$

Displaying "dusk_t"

$\mathrm{step} := 0..(60 \cdot 24 - 1)$

"step" is a counter, increasing from zero, in one-minute intervals (1 is the default increase step), up to the total number of minutes in 24 hours (count of 24*60 minus 1).

$t_{\mathrm{step}} := 1 + \mathrm{step}$

t is a set of time values, covering all minute numbers, at one minute intervals, starting at one minute after midnight, for 24 hours.

To calculate irradiation (G,Gd,Gc) at each minute interval

The calculated irradiation values are given the name "solarg" / "solargd" / "solargc", and calculated at each time step ("step") during the 24 hours.

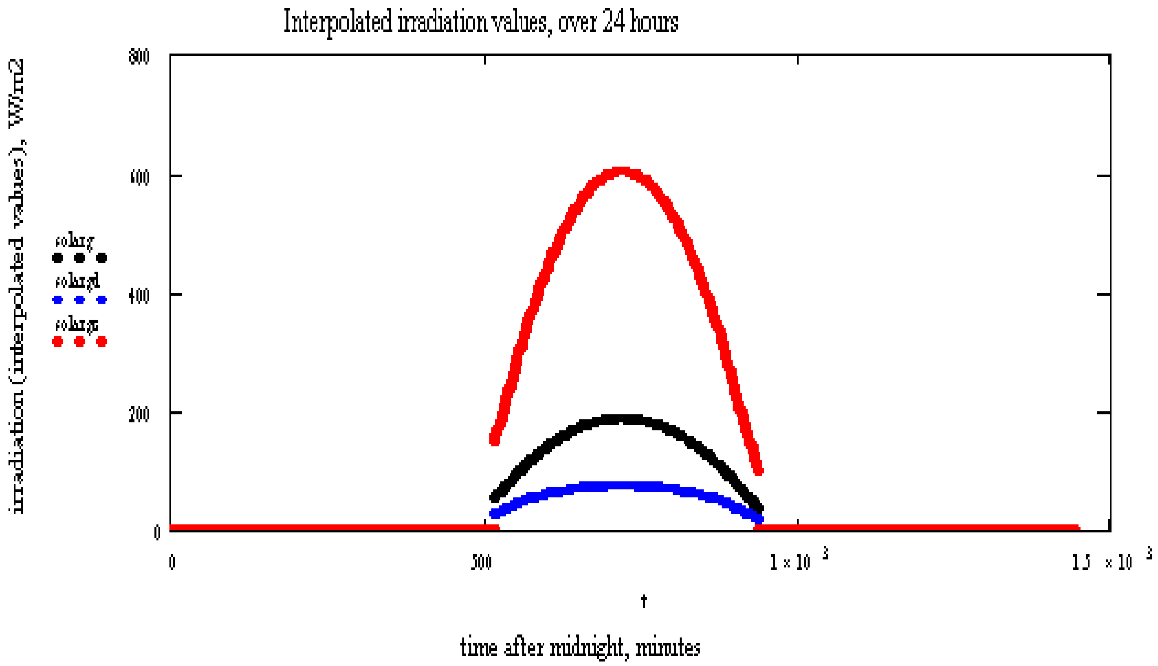
The "if" functions assign a value of zero to the irradiation, if the time value is before dawn or after dusk.

The "otherwise" function commands a calculation of the interpolated values at all times between dawn and dusk.

$$\text{solarg}_{\text{step}} := \left| \begin{array}{l} 0 \ \text{ if } \ t_{\text{step}} < \text{dawn\_t} \\ 0 \ \text{ if } \ t_{\text{step}} > \text{dusk\_t} \\ \text{linterp}\left(\text{minuteno}, \text{solarG}, t_{\text{step}}\right) \ \text{ otherwise} \end{array} \right.$$

$$\text{solargd}_{\text{step}} := \left| \begin{array}{l} 0 \ \text{ if } \ t_{\text{step}} < \text{dawn\_t} \\ 0 \ \text{ if } \ t_{\text{step}} > \text{dusk\_t} \\ \text{linterp}\left(\text{minuteno}, \text{solarGd}, t_{\text{step}}\right) \ \text{ otherwise} \end{array} \right.$$

$$\text{solargc}_{\text{step}} := \left| \begin{array}{l} 0 \ \text{ if } \ t_{\text{step}} < \text{dawn\_t} \\ 0 \ \text{ if } \ t_{\text{step}} > \text{dusk\_t} \\ \text{linterp}\left(\text{minuteno}, \text{solarGc}, t_{\text{step}}\right) \ \text{ otherwise} \end{array} \right.$$



These computed values of t, solarg, solargd and solargc, are combined into a single matrix, called "allsolarJanS35"

3. Exporting the data to a new file

These computed values of t, solarg, solargd and solargc, are combined into a single matrix, called "allsolarJanS35"

$$\mathrm{allsolarJanS35} := \mathrm{augment}(\mathrm{t}, \mathrm{solarg}, \mathrm{solargd}, \mathrm{solargc})$$

The matrix "allsolarJanS35" is exported to a csv file with the same name.

APPENDIX 7 CALCULATION: READING SOLAR DATA FROM PVGIS. A SECOND EXAMPLE OF A MATHCAD FILE. JUNE, WITH TIME CORRECTION (BST)

Reading solar data from PVGIS

1. Inserting a component into Mathcad that has time and solar irradiation data

This file reads outputs from PVGIS (here: G, Gd and Gc) at the timesteps on PVGIS, and puts these in a format to be used by the "calculation" Mathcad sheet.

PVGIS define:		
	G	- global irradiance on a fixed plane (W/m2)
	Gd	- diffuse irradiance on a fixed plane (W/m2)
	Gc	- global clear-sky irradiance on a fixed plane (W/m2)

First, PVGIS is run, using "Glasgow" as a location. In PVGIS, inputting "Glasgow" gives coordinates 55.864 latitude, -4.252 longitude, or 55 deg 51' 51" North and 4 deg 15 ' 6" West. The "text file" output option is selected.

An example of a text file output for January, south facing, roof angle 35 degrees, is used, and appended in Appendix 1.

The text file output from the PVGIS run is manually copied into an Excel workbook.
Then a blank column in the Excel workbook is used to calculate a "minutenumber" - number of minutes elapsed since midnight - from the 24hr time listed in the PVGIS data. This is done using the Excel function HOUR and MINUTE. (e.g. in January, the first time at which there are data is 8:37AM, and the corresponding first "minute number" is calculated (in Excel) to be 517.) Blank columns between data are deleted.

This Excel file is named according to PVG - orientation - angle.
For example, output from a south-facing, 35 degree, is in a file called "PVGS35".
The month is in the name of the worksheet within the file: e.g. January output is in a worksheet "JanS35", and the June output is in a worksheet "JunS35".

An extract from this Excel worksheet is now inserted into this Mathcad workbook (using Insert - Component - Excel sheet). The insertion instructions include:
Outputs:0;
Inputs: 1 - which sheet in the Excel file to read, and which row and column of the sheet to start and end with. The inserted component is instructed (manually) to only read rows populated with data, and to read columns of "minute number", "G", "Gd" and "Gc". The component is given the same name as the Excel sheet (no file extension).
(As an alternative, the component could read direct from the text file output of PVGIS. It would not compute the hour number. This could be done separately in Mathcad.)

$\mathrm{ORIGIN} := 1$

PVG35 :=

Worksheet

Displaying part of this component (Opening in Mathcad allows one to scroll down the table to read all data points.)

PVG35 =

	1	2	3	4
1	232	38	37	21
2	247	49	48	27
3	262	60	59	33
4	277	71	70	39
5	292	82	80	45
6	307	92	91	...

"Minuteno" is defined as a vector, populated with the first column of data in the component PVGS35. (Row and column numbers start at zero unless otherwise assigned).

$minuteno := PVG35^{\langle 1 \rangle}$

Irradiation G, Gd and Gc are vectors, populated with the following columns, respectively:

$solarG := PVG35^{\langle 2 \rangle}$

$solarGd := PVG35^{\langle 3 \rangle}$

$solarGc := PVG35^{\langle 4 \rangle}$

Displaying these readings in tables and in a graph:

minuteno =

	1
1	232
2	247
3	262
4	277
5	292
6	307
7	322
8	...

solarG =

	1
1	38
2	49
3	60
4	71
5	82
6	92
7	102
8	...

solarGd =

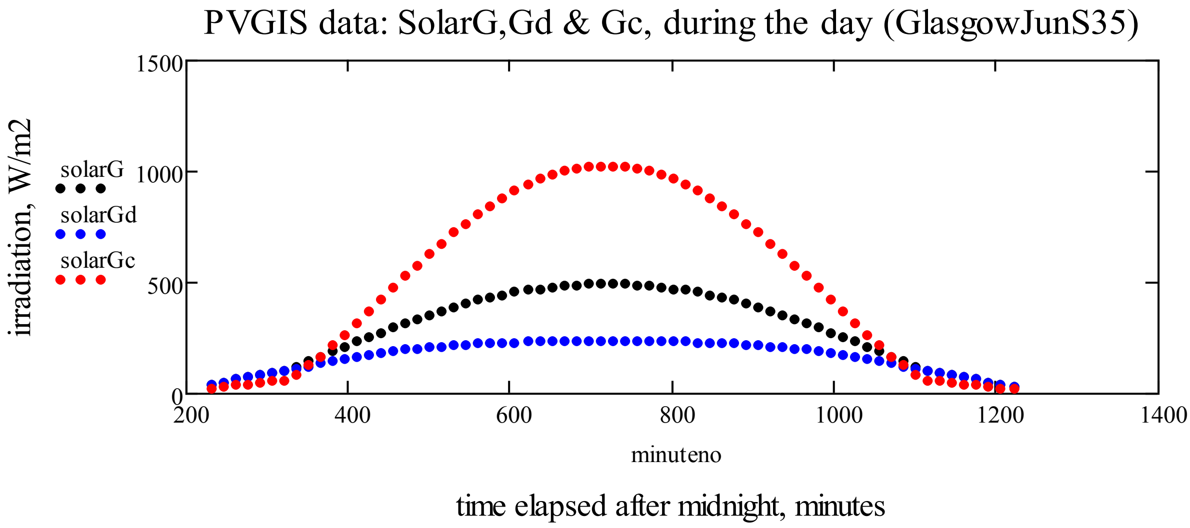
	1
1	37
2	48
3	59
4	70
5	80
6	91
7	101
8	...

solarGc =

	1
1	21
2	27
3	33
4	39
5	45
6	50
7	56
8	...

Maximum values are shown:-

$max(minuteno) = 1222$ $max(solarG) = 488$ $max(solarGd) = 232$ $max(solarGc) = 1020$



2. Filling in "gaps" in PVGIS data

Interpolating data to calculate G, Gd, Gc at one-minute intervals, and inserting "zero" irradiation values before dawn and after dusk.

Background
PVGIS lists data at 15 minute intervals.
As demand data at one-minute intervals will be used, it is necessary to calculate G, Gd, and Gc at one-minute intervals. The linear interpolation function in Mathcad is used.

PVGIS does not list any data during the night. Thus values (of zero) need to be assigned to irradiation during the night.

Calculation

The number of data points in each vector is counted by "length(vectorname)="

$\text{length}(\text{minuteno}) = 67$

This is displaying the number of data points in "minuteno", i.e. the number of 15 minute time-steps at which there are data. (This example is in summer. At other times of year, when days are longer, the vector will have fewer data points.)

$\text{dawn\_t} := \text{minuteno}_1$

$\text{dawn\_t} = 232$

"dawn time" is defined as the first reading of "minuteno", i.e. the earliest time in the day at which there are data.
Displaying "dawn_t"

$\text{dusk\_t} := \text{minuteno}_{\text{length}(\text{minuteno})}$

"dusk time" is the last reading of "minuteno", i.e. the latest time in the day at which there are data.

$\text{dusk\_t} = 1222$

Displaying "dusk_t"

$\text{step} := 1 .. (60 \cdot 24)$

"step" is a counter, increasing from zero, in one-minute intervals (1 is the default increase step), up to the total number of minutes in 24 hours (count of 24*60 minus 1).

$t_{\text{step}} := \text{step}$

t is a set of time values, covering all minute numbers, at one minute intervals, starting at one minute after midnight, for 24 hours.

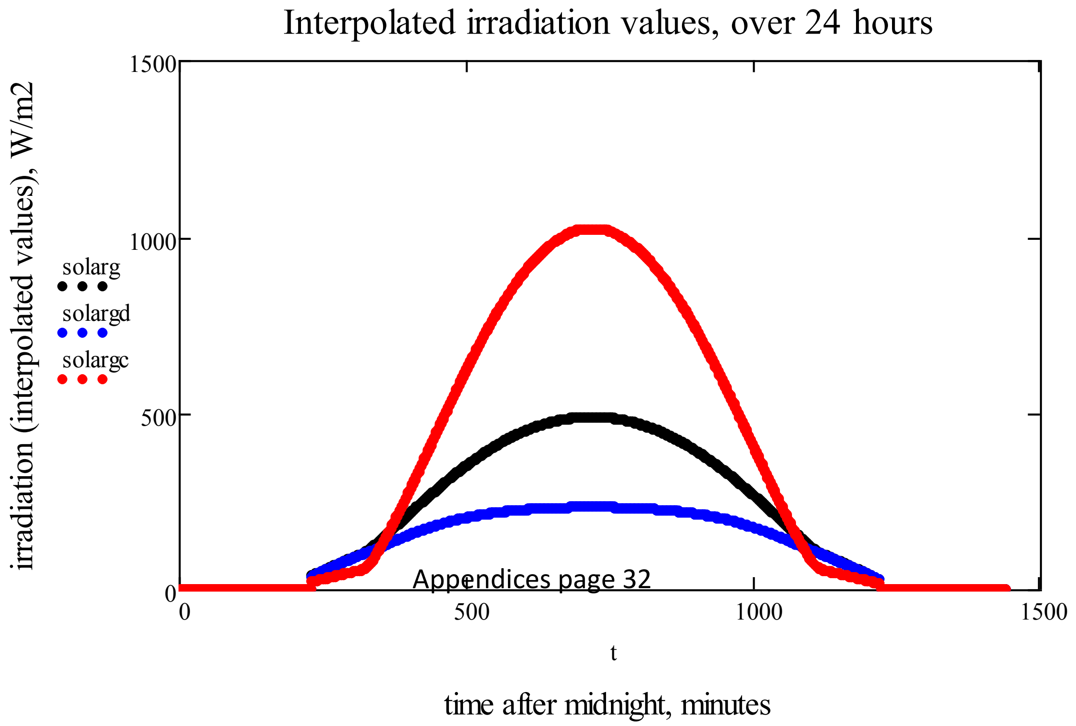
To calculate irradiation (G, Gd, Gc) at each minute interval

The calculated irradiation values are given the name "solarg" / "solargd" / "solargc", and calculated at each time step ("step") during the 24 hours.
The "if" functions assign a value of zero to the irradiation, if the time value is before dawn or after dusk.
The "otherwise" function commands a calculation of the interpolated values at all times between dawn and dusk.

$$solarg_{step} := \left| \begin{array}{l} 0 \ \text{ if } \ t_{step} < dawn\_t \\ 0 \ \text{ if } \ t_{step} > dusk\_t \\ \text{linterp}\left(minuteno, solarG, t_{step}\right) \ \text{ otherwise} \end{array} \right.$$

$$solargd_{step} := \left| \begin{array}{l} 0 \ \text{ if } \ t_{step} < dawn\_t \\ 0 \ \text{ if } \ t_{step} > dusk\_t \\ \text{linterp}\left(minuteno, solarGd, t_{step}\right) \ \text{ otherwise} \end{array} \right.$$

$$solargc_{step} := \left| \begin{array}{l} 0 \ \text{ if } \ t_{step} < dawn\_t \\ 0 \ \text{ if } \ t_{step} > dusk\_t \\ \text{linterp}\left(minuteno, solarGc, t_{step}\right) \ \text{ otherwise} \end{array} \right.$$



3. Exporting the data to a new file

These computed values of t, solarg, solargd and solargc, are combined into a single matrix, called "allsolarJunS35"

$$\mathrm{allsolarJunS35} := \mathrm{augment}(t, \mathrm{solarg}, \mathrm{solargd}, \mathrm{solargc})$$

The matrix "allsolarJunS35" is exported to a csv file with the same name.

4. Correcting local times to British Summer Time

4.a) Converting from local time to Greenwich Mean Time

All PVGIS data are in local times.

Here these are changed to GMT.

Time difference from GMT is calculated from longitude, -4.252deg

$$\mathrm{lon} := -4.252\mathrm{deg}$$

$$\mathrm{timediff\_GMT} := \mathrm{lon} \cdot 24 \cdot 60 \frac{\mathrm{min}}{360\mathrm{deg}}$$

$$\mathrm{timediff\_GMT} = -17.008 \cdot \mathrm{min}$$

displaying local time difference from GMT.

4. b) Converting from Greenwich Mean Time to British Summer Time

Clocks advance one hour, so a further increase in time of one hour must be added.

$$\mathrm{timediff\_BST} := \mathrm{timediff\_GMT} - 60\mathrm{min}$$

“minus" term used because "timediff_GMT" is negative; both changes are additive.

$$\mathrm{timediff\_BST} = -77.008 \cdot \mathrm{min}$$

$$\mathrm{stepGlas} := 78 .. 1440 + 77$$

list of minute numbers, starting from time difference+1, for 24 hours.

$$\mathrm{solargGlas1517}_{\mathrm{stepGlas}} := \mathrm{solarg}_{\mathrm{stepGlas}-77}$$

$$\mathrm{solargdGlas1517}_{\mathrm{stepGlas}} := \mathrm{solargd}_{\mathrm{stepGlas}-77}$$

$$\mathrm{solargcGlas1517}_{\mathrm{stepGlas}} := \mathrm{solargc}_{\mathrm{stepGlas}-77}$$

New data sets, “solargGlas1517”, “solargdGlas1517” and “solargcGlas1517” defined, each with 1517 timesteps

Some sample value are displayed below:

$$\mathrm{solarg}_{515} = 366.733$$

$$\mathrm{solarg}_{516} = 367.867$$

$$\mathrm{solarg}_{517} = 369$$

$$\mathrm{solargGlas1517}_{532} = 290.2$$

$$\mathrm{solargGlas1517}_{533} = 291.6$$

$$\mathrm{solargGlas1517}_{534} = 293$$

$$\mathrm{solargGlas1517}_{1517} = 0$$

$$\mathrm{solarGlas1517}_{1518} = ▮$$

The final timestep is 1517, so there is no value of "solarGlas1517" at timestep 1518.

Augmenting the three data sets into a single matrix,

$\mathrm{allsolarGlas1517} := \mathrm{augment}(\mathrm{solargGlas1517}, \mathrm{solargdGlas1517}, \mathrm{solargcGlas1517})$

$\mathrm{Gs} := 1 .. 3$

Defining "Gs" as the name of the 3 columns with different "G" values.

$\mathrm{allsolarGlas}_{\mathrm{step}, \mathrm{Gs}} := \mathrm{allsolarGlas1517}_{\mathrm{step}, \mathrm{Gs}}$

Defining matrix "allsolarGlas" as the same as the previous one, but stopping after 24 hours, i.e. 1440 values.

$\mathrm{rows}(\mathrm{allsolarGlas1517}) = 1517$

$\mathrm{rows}(\mathrm{allsolarGlas}) = 1440$

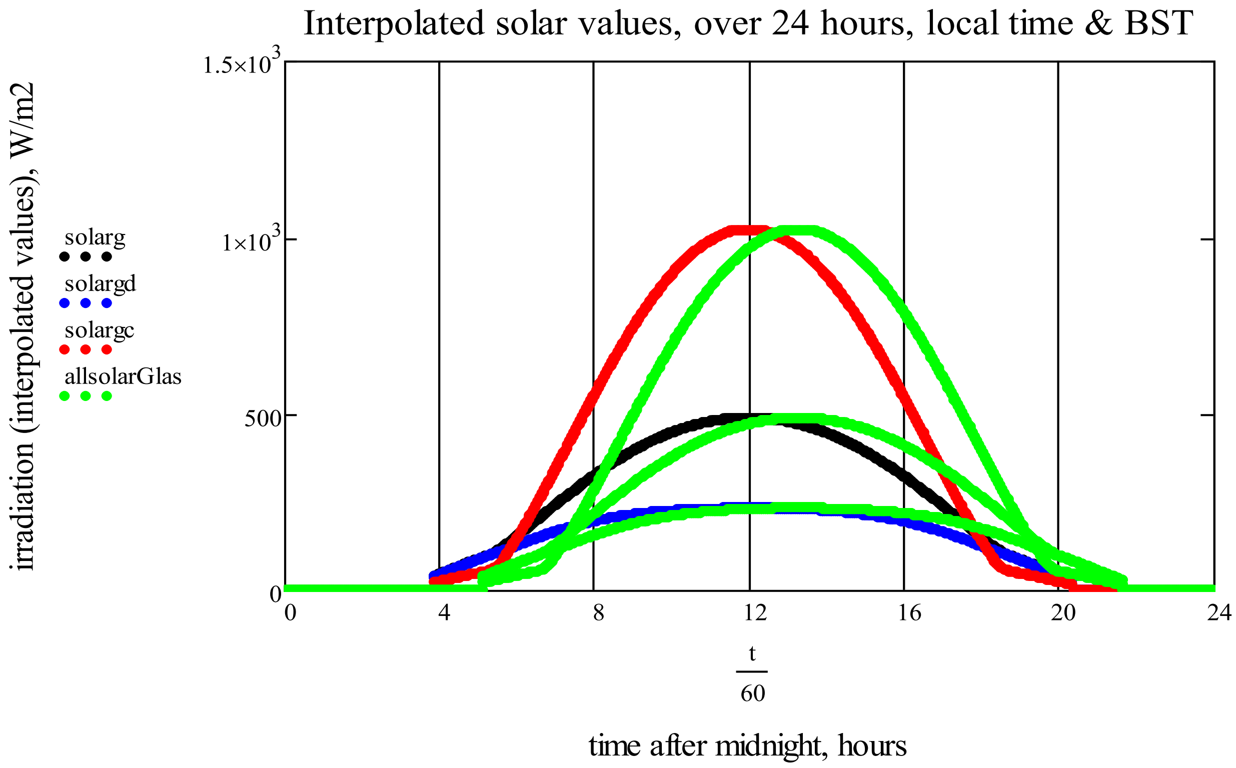
Checking the matrices have correct numbers of rows.

Augmenting into a new matrix, with time

$\mathrm{allsolarGlasJunS35} := \mathrm{augment}(t, \mathrm{allsolarGlas})$

Exporting new data file with same name.

Displaying irradiance in local Glasgow time, and British Summer Time.



APPENDIX 8 CALCULATION OF THE ELECTRICITY GENERATED: AN EXAMPLE MATHCAD SHEET "ELECTRICITY IN"

To calculate the actual energy generated by PV panels, for a given building

Scenario 1: Urban. The building is a Glasgow tenement. There are six flats in a close, two on each floor, and three floors in the building.

1. Introduction

This calculation sheet takes data for solar irradiance (G,Gd,Gc), in W/m2 roof area, at every one-minute timestep. The data originate from PVGIS outputs (for a given location, orientation, roof angle and month). All values at one-minute intervals throughout the day and night are interpolated by Mathcad file "read JanS35solar data calc.xmcd", and exported to a csv file e.g. for January, the file is named "allsolarJanS35.csv".

This worksheet takes the solar radiation values at every minute, and from them, and other inputs in this worksheet, calculates the electricity generated, in W.

2. Inputs

Previously defined inputs: location, month, direction, angle of slope.

These have been previously selected when choosing appropriate PVGIS output.

Scenario inputs: type of building.

This file incorporates: dimensions of building ("width", "length"), number of households which share the roof ("flatnum"), and efficiency of the PV panels ("Eff"). This sheet also uses the angle of slope of the roof to calculate the roof area from the floor area.

To calculate the actual energy generated by PV panels, for a given building

Building dimensions:

$\text{length} := 11\text{m}$

$\text{floorarea} := \text{width} \cdot \text{length}$

Assuming a simple building shape, with half of roof facing one direction and the other half facing the opposite direction.

$\text{flatnum} := 3$

Number of flats under this area of roof

$\text{width} := 9\text{m}$

Assuming panels would only be fitted to the south (or partly south)-facing side

$$\text{floorareaPVph} := \frac{\text{floorareaPV}}{\text{flatnum}}$$

floorareaPV, i.e. floor area suitable to have PV fitted above it, is taken as half of the total floor area.

$\text{floorareaPV} := \text{floorarea} \cdot \text{PV\_roof\_frac}$

floorareaPVph is the area per household

$\text{PV\_roof\_frac} := 50\%$

Proportion of roof area to be fitted with panels

Angle of roof is inputted here

$$\mathrm{roofslope} := 35^{\circ}$$

The area of roof which would have PV panels, in total and per household, is calculated and displayed below.

$$\mathrm{arearoofPV} := \frac{\mathrm{floorareaPV}}{\cos(\mathrm{roofslope})} \qquad \mathrm{arearoofPVph} := \frac{\mathrm{arearoofPV}}{\mathrm{flatnum}}$$

$$\mathrm{arearoofPV} = 60.4\,\mathrm{m}^2 \qquad \mathrm{arearoofPVph} = 20.1\,\mathrm{m}^2$$

This assumes the entire area is covered in PV panels (probably unrealistic, but allows comparison between different cases):

Efficiency ("Eff") of PV panels in converting solar irradiation to electrical energy is assumed here.

$$\mathrm{Eff} := 12\%$$

3. Importing solar radiation from PVGIS, modified to give radiation at one-minute time steps throughout the day

Chosen month: January

Aspect of roof: south-facing

Importing from file "allsolarJanS35.csv" (created by Mathcad file "read JanS35 solar data calc.xmcd")

$$\mathrm{allsolarJanS35} :=$$

(filename displayed in Mathcad)

The file stores data numbers, with no units, so the units are assigned below.

$$\mathrm{minuteno} := \mathrm{allsolarJanS35}^{\langle 0 \rangle}$$

"minuteno" - minute number after midnight, minutes

$$\mathrm{solarg} := \mathrm{allsolarJanS35}^{\langle 1 \rangle} \cdot 1\,\frac{\mathrm{W}}{\mathrm{m}^2}$$

"solarg" - global irradiation on surface at that minute number, W/m2

$$\mathrm{solargd} := \mathrm{allsolarJanS35}^{\langle 2 \rangle} \cdot 1\,\frac{\mathrm{W}}{\mathrm{m}^2}$$

"solargd" - diffuse irradiation on surface at that minute number

$$\mathrm{solargc} := \mathrm{allsolarJanS35}^{\langle 3 \rangle} \cdot 1\,\frac{\mathrm{W}}{\mathrm{m}^2}$$

"solargc" - clear sky global solar irradiation on that surface at the minute number

4. Calculating electricity generation

To calculate electricity generated, per household (assuming each household has access to equal share of the roof area):-

elect_av := solarg·arearoofPVph·Eff

elect_cloudy := solargd·arearoofPVph·Eff

elect_clear := solargc·arearoofPVph·Eff

The terms "elect_av", "elect_cloudy" and "elect_clear" are vectors, i.e. values of the electricity generation, in W, at each one-minute time step.

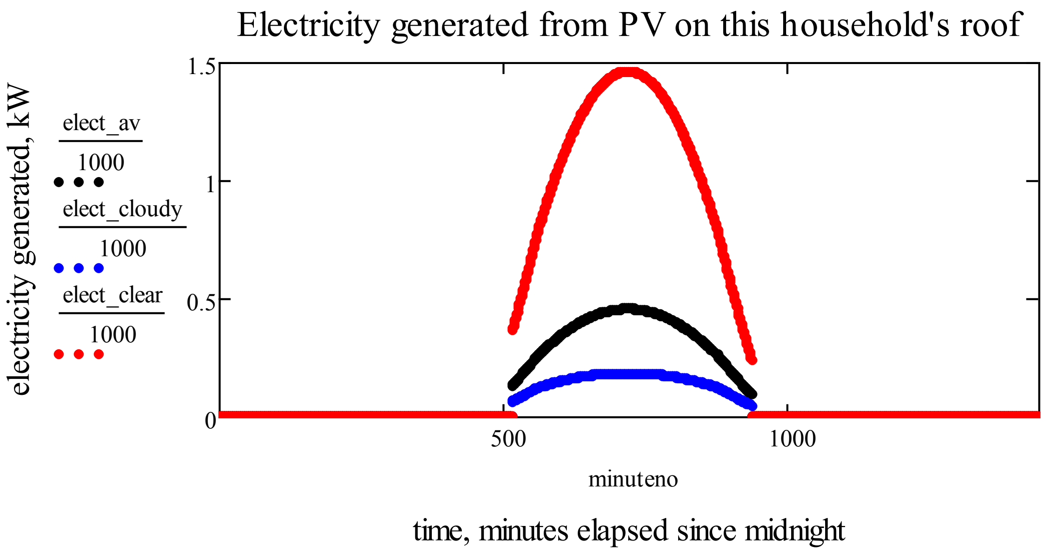
Displaying peak electricity generation

max(elect_av) = 454 W

max(elect_cloudy) = 181 W

max(elect_clear) = 1460 W

And displaying all values of electricity generation during the day and night graphically:-



5. Check calculation: the total electrical energy generated during a day is evaluated, per square metre of roof and floor area, for an average, cloudy and clear day. These totals are compared with a separate calculation on an Excel worksheet, based on PVGIS data.

5. a) The electricity generated (J or kWh) at each minute is evaluated from the values "elect_av", "elect_cloudy" and "elect_clear".

The sum for the total generation in the day is then evaluated.

$i := 0..\ \mathrm{rows(minuteno)} - 1$	counting all values from minute number 1 (time 00:01) to the last minute number (at time 24:00).
$\mathrm{rows(minuteno)} = 1440$	displaying the number of one-minute values in the day.

Defining the total amount of electricity generated in the day: ("dayelect_av", dayelect_cloudy" and "dayelect_clear") as the sum of electricity generated at each time step during the day, * 60 seconds per one-minute timestep.

$$\mathrm{dayelect\_av} := \sum_{i} \mathrm{elect\_av}_{i} \cdot 60\mathrm{s}$$

$$\mathrm{dayelect\_cloudy} := \sum_{i} \mathrm{elect\_cloudy}_{i} \cdot 60\mathrm{s}$$

$$\mathrm{dayelect\_clear} := \sum_{i} \mathrm{elect\_clear}_{i} \cdot 60\mathrm{s}$$

Displaying results for total day electricity, in J

$$\mathrm{dayelect\_av} = 8 \times 10^{6}\,\mathrm{J}$$

$$\mathrm{dayelect\_cloudy} = 4 \times 10^{6}\,\mathrm{J}$$

$$\mathrm{dayelect\_clear} = 3 \times 10^{7}\,\mathrm{J}$$

To display in kWh, first it is necessary to define "kWh" in Mathcad.

$$\mathrm{kWh} := 1000 \cdot 3600\mathrm{J}$$

Displaying daily electricity generated, in kWh

$$\mathrm{dayelect\_av} = 2 \cdot \mathrm{kWh}$$

$$\mathrm{dayelect\_cloudy} = 1 \cdot \mathrm{kWh}$$

$$\mathrm{dayelect\_clear} = 7 \cdot \mathrm{kWh}$$

5. b) Next, the sheet back calculates to irradiation per sq. metre of floor and roof.

These values are compared with day total irradiation values calculated separately on Excel sheet: "roofanglefloorareaGlasgowJan_June.xlxs", sheet "SJanG".

	Mathcad calculation of day total solar irradiation, in kWh/sq. metre.	Day total irradiation (kWh per sq. metre) calculated in Excel sheet "roofanglefloorareaGlasgowJan_June.xlxs, sheet SJanG",
Day irradiation per sq. metre of roof		
Average day	$\frac{\text{dayelect\_av}}{\text{Eff}\cdot\text{arearoofPVph}} = 0.975\cdot\frac{\text{kWh}}{\text{m}^2}$	Excel sheet value: 0.985kWh
Cloudy day	$\frac{\text{dayelect\_cloudy}}{\text{Eff}\cdot\text{arearoofPVph}} = 0.415\cdot\frac{\text{kWh}}{\text{m}^2}$	Excel sheet value: 0.421kWh
Clear day	$\frac{\text{dayelect\_clear}}{\text{Eff}\cdot\text{arearoofPVph}} = 3.064\cdot\frac{\text{kWh}}{\text{m}^2}$	Excel sheet value: 3.093kWh
Day irradiation per sq. metre of floor		
Average day	$\frac{\text{dayelect\_av}}{\text{Eff}\cdot\text{floorareaPVph}} = 1.190\cdot\frac{\text{kWh}}{\text{m}^2}$	Excel sheet value: 1.203kWh
Cloudy day	$\frac{\text{dayelect\_cloudy}}{\text{Eff}\cdot\text{floorareaPVph}} = 0.507\cdot\frac{\text{kWh}}{\text{m}^2}$	Excel sheet value: 0.514kWh
Clear day	$\frac{\text{dayelect\_clear}}{\text{Eff}\cdot\text{floorareaPVph}} = 3.741\cdot\frac{\text{kWh}}{\text{m}^2}$	Excel sheet value: 3.776kWh

5. c) Results of check

Day total irradiation calculated separately in Mathcad and Excel, agree closely.

(Small differences are expected, as in the Excel sheet, the 15 minute values were summed and multiplied, and in Mathcad, they were interpolated.)

5. d) Conclusion of check

These calculations are probably correct.

6. Exporting data file with electricity generated at every one minute time step

Converting electricity generation values to unit-less numbers, to allow incorporation into matrix with values of different units (here, including "minuteno").

$$\text{elect\_av\_no} := \frac{\text{elect\_av}}{W} \qquad \text{elect\_cloudy\_no} := \frac{\text{elect\_cloudy}}{W}$$

$$\text{elect\_clear\_no} := \frac{\text{elect\_clear}}{W}$$

Creating a matrix by combining vectors: minuteno, and the electricity generated (number of Watts), on an average, cloudy and clear day.

$$\text{PVJanS35urban} := \text{augment}(\text{minuteno}, \text{elect\_av\_no}, \text{elect\_cloudy\_no}, \text{elect\_clear\_no})$$

Matrix PVJanS35urban
Exported to a csv file of
the same name.

APPENDIX 9 CALCULATION OF EXCESSES AND DEFICITS IN GENERATION AT EACH ONE-MINUTE TIME STEP. AN EXAMPLE MATHCAD SHEET “MAIN CALCULATOR”

Main calculator

1.Introduction

This sheet takes data for electrical demand, and generation from PV, and calculates the excess and deficit of electrical power at each time step. It then calculates the daily excess and deficit in electrical energy.

This worksheet performs the calculation for the case where there is *no electrical storage.*

A later sheet ("battcalc.xmcd") performs the calculation for a case where the system includes electrical storage.

2. Uploading generation and demand data

In order for all tables of data to start from number one, rather than zero, it is necessary to define the number assigned to the first column or row of data (called "ORIGIN" in Mathcad).

$\mathrm{ORIGIN} := 1$

$\mathrm{kWh} := 1000 \cdot 3600\mathrm{J}$

For January, roof South 35 deg, urban scenario

$\mathrm{PVJanS35urban} :=$

Data file "PVJanS35urban.csv" was uploaded from Mathcad sheet "electinJanS35urban.xmcd"

Demand for 2 person house, in January, weekday (from Richardson). In this case there are six runs (to simulate 6 houses).

$\mathrm{demJanwd2occ\_mins} :=$

copy of data from Richardson, columns for minute number and energy demand for all 6 runs

$\mathrm{demJanwd2occ} :=$

copy of data from Richardson, without minute number column, energy demand columns only

$\mathrm{runs} := 6$

3. defining vectors with supply and demand data

3. a) time counter, in minutes, from both supply and demand data sheets

$$minutenoPV := PVJanS35urban^{\langle 1 \rangle}$$

$$minutenoDemand := demJanwd2occ\_mins^{\langle 1 \rangle}$$

These two minute counters should be the same. Check below:

$minutenoPV_{600} = 600$

$minutenoDemand_{600} = 600$

the 600th count of both "minuteno" counts are the same. This is as it should be.

$rows(minutenoPV) = 1440$

$rows(minutenoDemand) = 1440$

Both counters have the same number of rows. Correct.

$count := 1 .. 1440$

inserting a counter for every minute during the day

$$timediff_{count} := minutenoPV_{count} - minutenoDemand_{count}$$

computing the difference between the two time counters a every minute interval

$$timediffsum := \sum_{count} timediff_{count}$$

Adding all the time differences during the day

$timediffsum = 0$

Conclusion: there is no difference between the two time counters. They are both correct.

3. b) Generation on average, cloudy and clear days, with "Watts" assigned:-

$$PV\_av := PVJanS35urban^{\langle 2 \rangle} \cdot 1W$$

$$PV\_cloudy := PVJanS35urban^{\langle 3 \rangle} \cdot 1W$$

$$PV\_clear := PVJanS35urban^{\langle 4 \rangle} \cdot 1W$$

Check

$PV\_av_{600} = 339\,W$

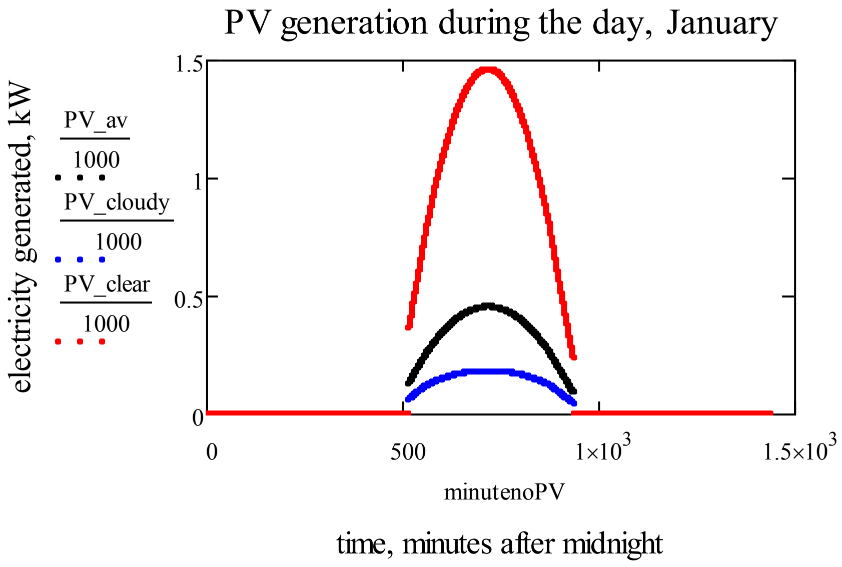
$\max(PV\_av) = 454\,W$

This is a check of generation at 600 minutes: as per "elect_in" sheet for "average" day

$\max(PV\_cloudy) = 181\,W$

$\max(PV\_clear) = 1460\,W$

Check max generation for average, cloudy and clear day. Values same as previously calculated.



The calculations below initially use the generation on a clear day only.

3.c) Demand assigned for the runs

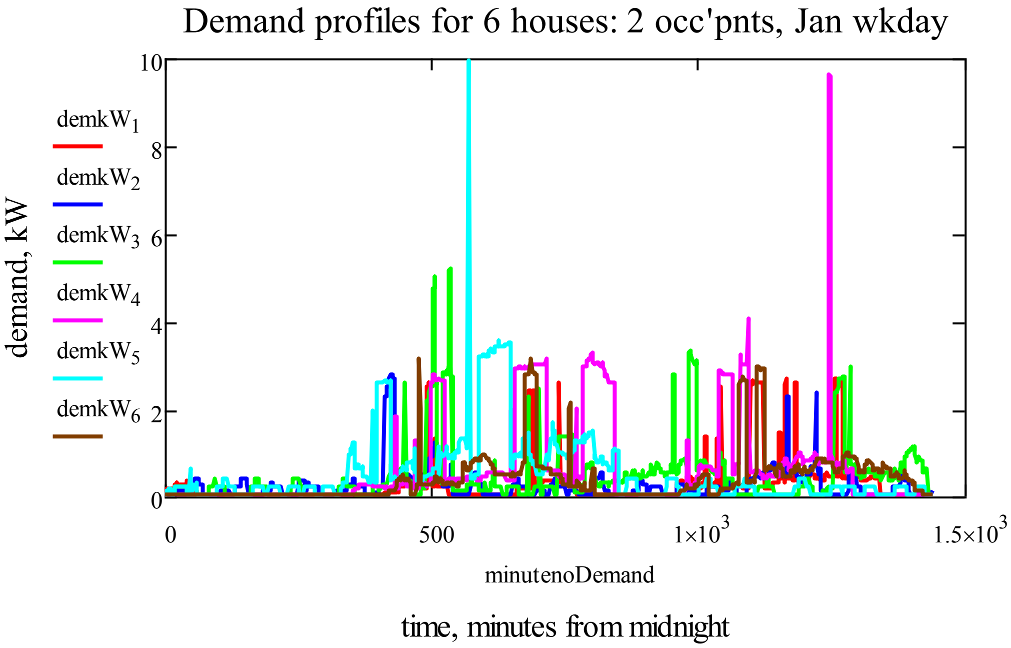
Demand on runs 1 to 6

$$run := 1..6$$

$$demand_{run} := demJanwd2occ^{\langle run \rangle} \cdot 1W$$

$$demkW := \frac{demand}{1000}$$

6 demand vectors, of runs 1 to 6, have been created, for the demand at one-minute intervals for each run. They are shown graphically below.



$\max(demkW_5) = 9.952\,W$ $\max(demkW_4) = 9.65\,W$

3. d) Aggregate demand for all 6 houses is computed

Aggregated demand for the 6 houses, over the 24 hours, is calculated below.

$$\text{aggdemand}_{\text{count}} := \sum_{\text{run}} \left(\text{demand}_{\text{run}}\right)_{\text{count}}$$

counting in one minute intervals

"aggdemand" is the aggregate demand, of all the runs (in this case 6), computed at each minute (count).

"demand" and "aggdemand" are in Watts. To display in kW:-

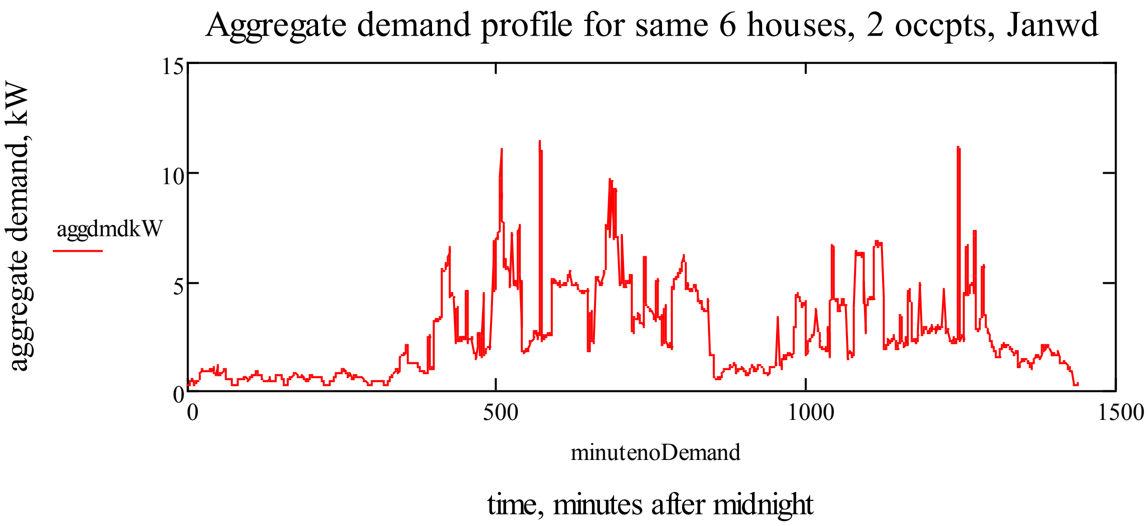
$$\text{aggdmdkW}_{\text{count}} := \sum_{\text{run}} \left(\text{demkW}_{\text{run}}\right)_{\text{count}}$$

"demkW" is defined above as "demand/1000"

The calculation can also be written as here: it is the same calculation, and produces same graph.

$$\text{aggdmd2}_{\text{count}} := \sum_{\text{run}} \left(\text{demJanwd2occ}^{\langle \text{run} \rangle}\right)_{\text{count}}$$

The aggregate demand is displayed graphically below.



Data file for aggregate demand is exported.

$$\sum \text{aggdemand} \cdot 60\text{s} = 62.1 \cdot \text{kWh}$$

$$\max(\text{aggdemand}) = 11.4 \cdot \text{kW}$$

4. Calculating excess and deficit in PV generation during the day, for a clear day.

This section calculates excess and deficit power ("ExcessP" and "DeficitP") at each time step ("count", defined above) and individual house ("run")

$$\text{ExcessP}_{\text{count},\,\text{run}} := \left| \begin{array}{l} \left[\text{PV\_clear}_{\text{count}} - \left(\text{demand}_{\text{run}}\right)_{\text{count}}\right] \text{ if } \text{PV\_clear}_{\text{count}} \geq \left(\text{demand}_{\text{run}}\right)_{\text{count}} \\ 0 \text{ otherwise} \end{array} \right.$$

$$\text{DeficitP}_{\text{count},\,\text{run}} := \left| \begin{array}{l} \left[\left(\text{demand}_{\text{run}}\right)_{\text{count}} - \text{PV\_clear}_{\text{count}}\right] \text{ if } \left(\text{demand}_{\text{run}}\right)_{\text{count}} \geq \text{PV\_clear}_{\text{count}} \\ 0 \text{ otherwise} \end{array} \right.$$

At each timestep, the excess and deficit power is calculated.

The "otherwise" commands ensure excess and deficit are never negative.

ExcessP and DeficitP are both tables, of the excess and deficit at each minute number, and each

To check:

Displaying part of tables for deficits and excesses:

Columns 1-6 show deficits in power for the first few minutes after midnight - all around 50 - 200W. At the same time, the excesses in PV generation are all zero (because it is dark).

DeficitP =

	1	2	3	4	5	6
1	53	50	51	55	55	54
2	53	50	51	55	55	54
3	53	50	51	55	55	54
4	173	50	51	55	115	54
5	173	50	51	55	155	54
6	173	50	51	55	115	54
7	173	50	51	55	123	54
8	173	50	51	55	123	...

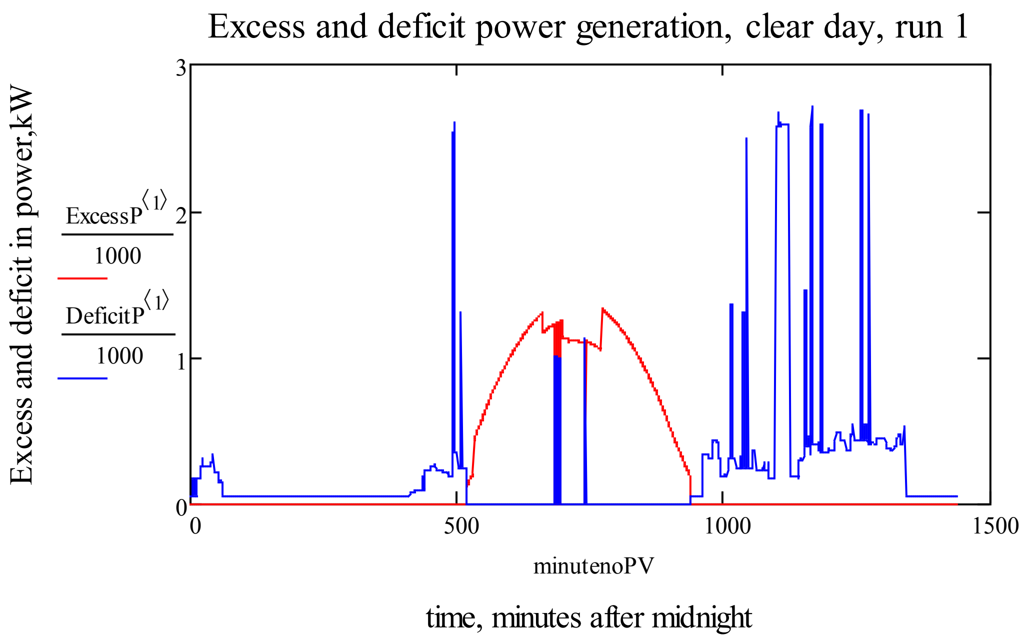
W

ExcessP =

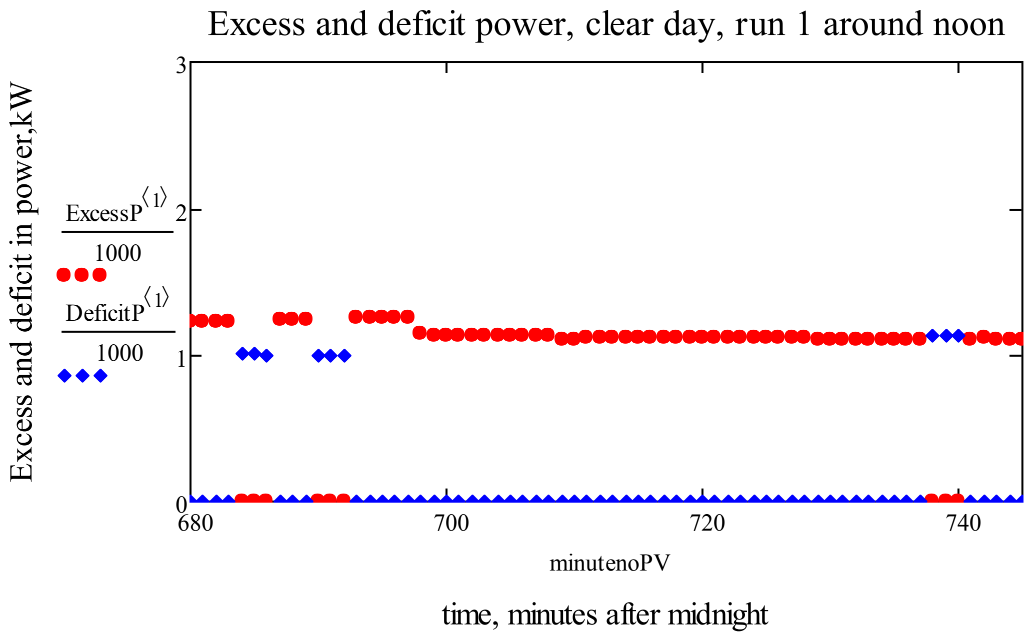
	1	2	3	4	5	6
1	0	0	0	0	0	0
2	0	0	0	0	0	0
3	0	0	0	0	0	0
4	0	0	0	0	0	0
5	0	0	0	0	0	...

W

The excess and deficit in power for each individual run (house) is displayed graphically below.



Investigating the unclear area 600-800 minutes

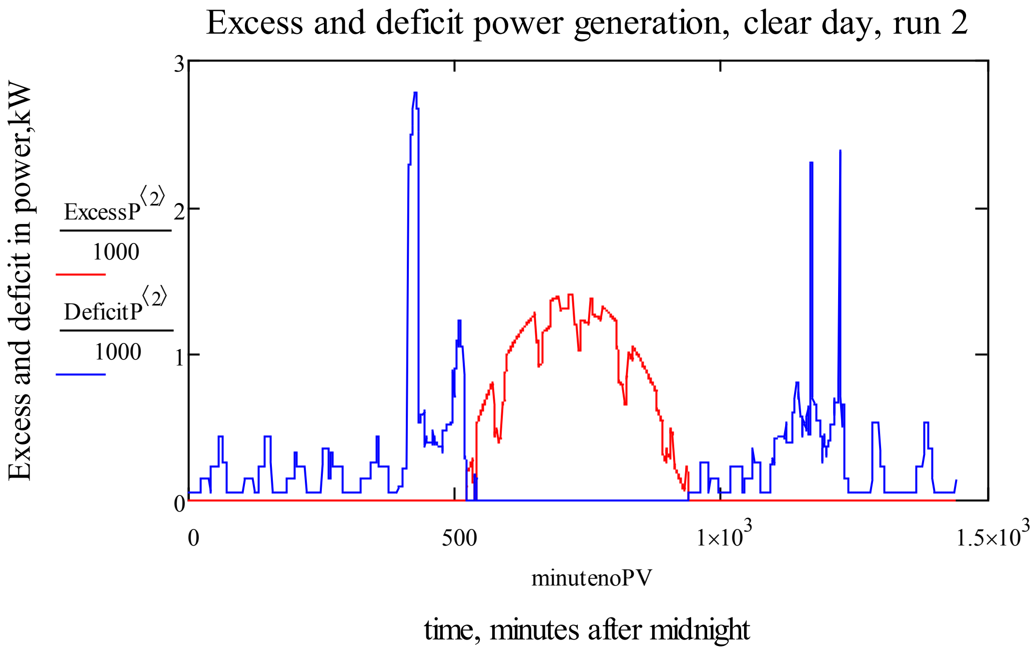


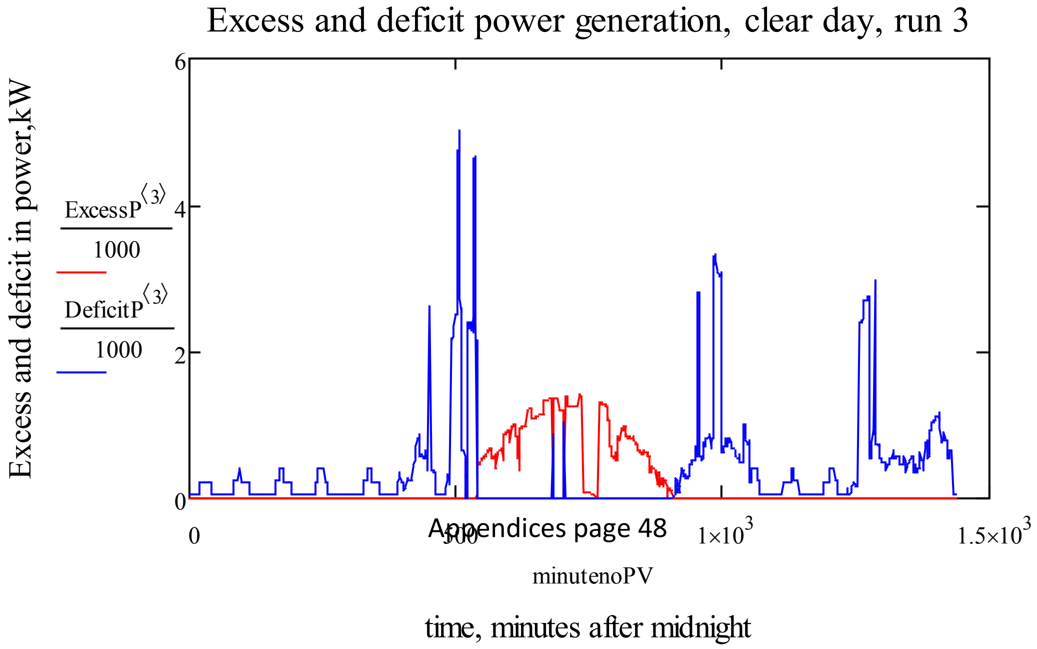
Between 680 and 700 minutes, there are two individual spikes in deficit, around 1kW, each lasting 3 minutes, at 684 and 690 minutes, breaking a general peak in excess.

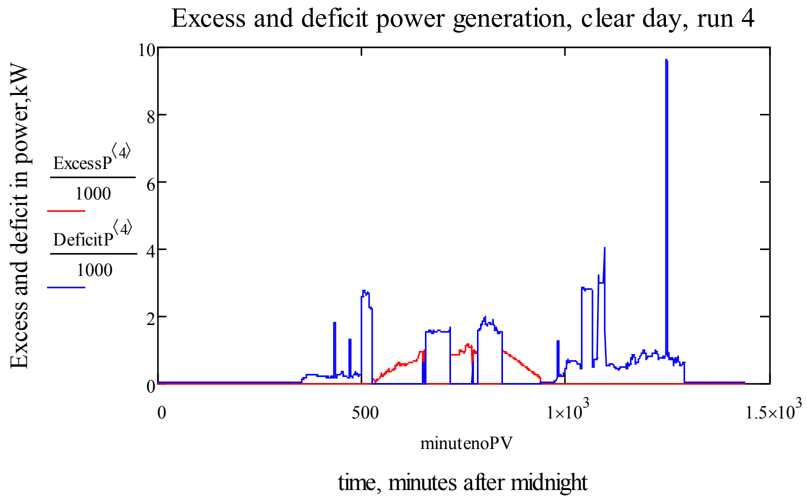
There is a later single spike in deficit, at 738 minutes, again, lasting for three minutes, breaking the peak in excess.

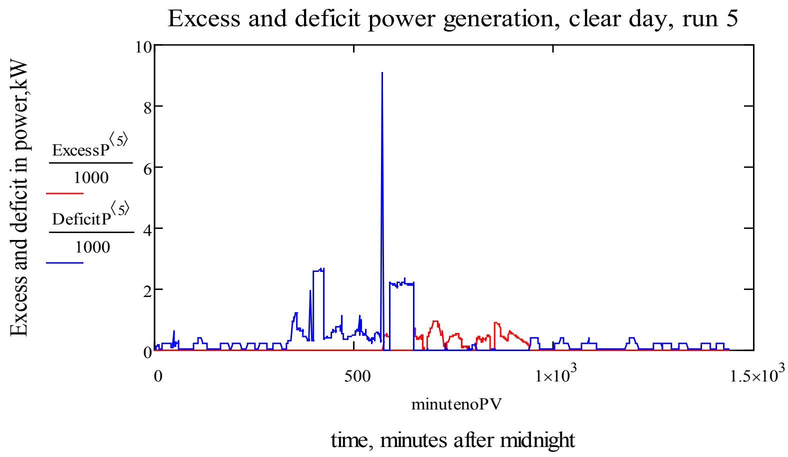
The calculation is correctly assigning positive or zero values to excess and deficits in power (no negative values). The graph is correct (though a little unclear) at these times.

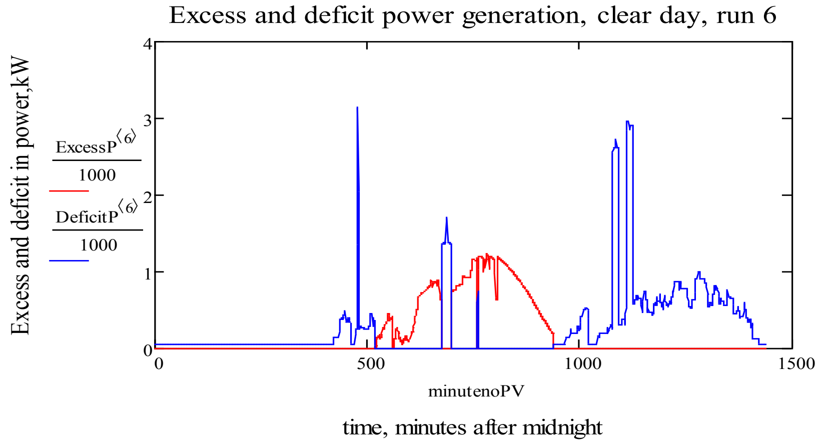
The excesses and deficits for the other runs are displayed below.



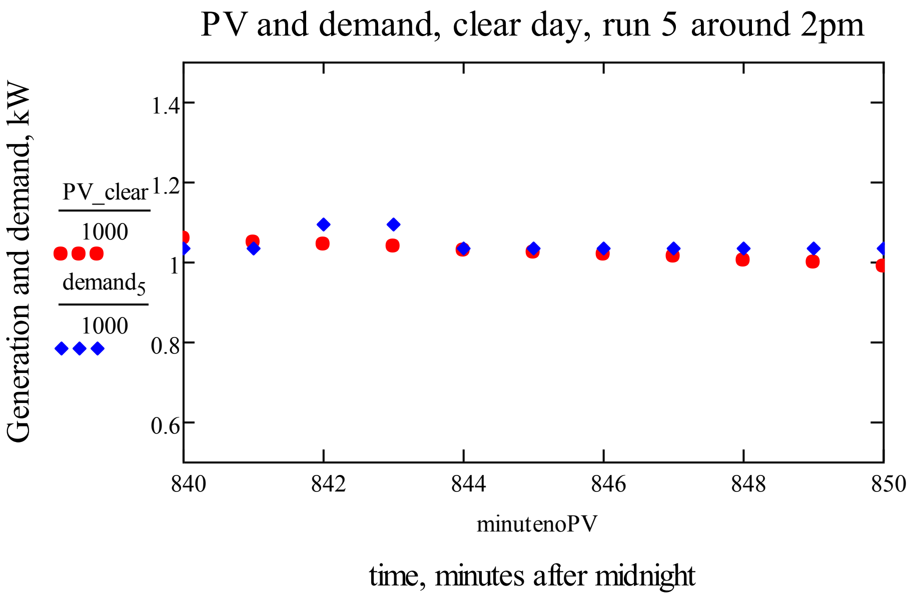


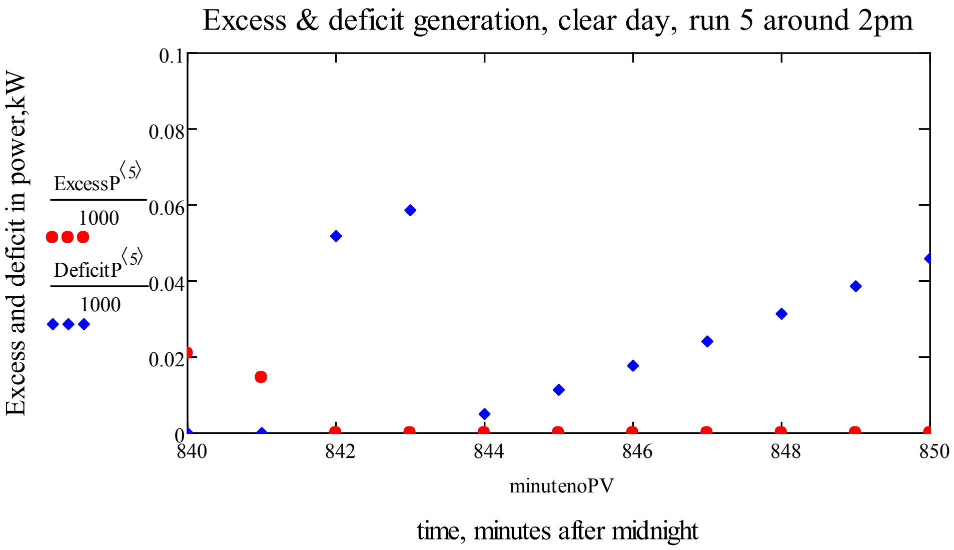

Excess and deficit power generation, clear day, run 4
Excess and deficit in power,kW
ExcessP⟨4⟩ / 1000
DeficitP⟨4⟩ / 1000
0
2
4
6
8
10
0
500
1×10^3
1.5×10^3
minutenoPV
time, minutes after midnight


Excess and deficit power generation, clear day, run 5
Excess and deficit in power,kW
ExcessP⟨5⟩ / 1000
DeficitP⟨5⟩ / 1000
0
2
4
6
8
10
0
500
1×10^3
1.5×10^3
minutenoPV
time, minutes after midnight


Excess and deficit power generation, clear day, run 6
Excess and deficit in power,kW
ExcessP⟨6⟩ / 1000
DeficitP⟨6⟩ / 1000
0
1
2
3
4
0
500
1000
1500
minutenoPV
time, minutes after midnight

Examination of run 5: ten minute section in the afternoon, 2pm, minute number 840.





Electricity generation and demand are closely matched, around 1kW. From minute number 840-850 (except 842-3) excess is declining and deficit is increasing because solar irradiation is reducing. At minute number 842-3 an extra 60W demand is switched on.

Exporting files with excess and deficit power data at each minute for each run

Two csv files are created, with values, for excess and deficit power at each timestep (in Watts).

5. Calculating daily totals of excess and deficit in energy

The above vector is a list of total Day Demand

for each run, 1-6.

$$\mathrm{DayExcessE}_{\mathrm{run}} := \sum \mathrm{ExcessP}^{\langle \mathrm{run} \rangle} \cdot 60\mathrm{s}$$

$$\mathrm{DayDeficitE}_{\mathrm{run}} := \sum \mathrm{DeficitP}^{\langle \mathrm{run} \rangle} \cdot 60\mathrm{s}$$

Defining the total excess and deficit energy for the day, for each run (individual house) as the sum of all the one-minute power deficits and excesses, multiplied by the number of seconds in each time step (60s).

$\mathrm{DayExcessE}_{\mathrm{run}} =$ ·kWh

6.378
6.231
4.755
3.068
2.039
4.486

$\mathrm{DayDeficitE}_{\mathrm{run}} =$ ·kWh

5.255
4.989
8.681
11.203
7.874
6.569

Displaying a listing of the total day excess and deficit for runs 1 to 6.

Looking at all 6 runs, computing the minimum, maximum and mean day excess and deficit:

$\min(\mathrm{DayExcessE}) = 2.039 \cdot \mathrm{kWh}$

$\max(\mathrm{DayExcessE}) = 6.378 \cdot \mathrm{kWh}$

$\min(\mathrm{DayDeficitE}) = 4.989 \cdot \mathrm{kWh}$

$\max(\mathrm{DayDeficitE}) = 11.203 \cdot \mathrm{kWh}$

Mean excess and deficit for the day, for the 6 runs, is computed below

$$\frac{\sum \mathrm{DayExcessE}}{\mathrm{runs}} = 4.493 \cdot \mathrm{kWh}$$

$$\frac{\sum \mathrm{DayDeficitE}}{\mathrm{runs}} = 7.429 \cdot \mathrm{kWh}$$

Check1

Manual addition of all excess power totals (in csv file "ExcessP_6runs.csv", exported from this sheet, section 4), and from the totals, calculation of the energy excess and deficit for the day.

Daily totals of energy excesses and deficits for each run agree with DayExcessE and DayDeficitE displayed above for each run.

It is thus believed these totals are correct.

Check2

Compare net generation day totals for each run, with net excess totals.

Evaluate the net generation for the day ("DayNetGen"), i.e. the day total generation, minus the day total demand, for each run.

Compare with the day total of the net excesses (excess minus deficit) calculated at each minute.

$$\text{DayPV\_clear} := \sum \text{PV\_clear} \cdot 60\text{s}$$

$$\text{DayPV\_clear} = 7.406 \cdot \text{kWh}$$

$$\text{DayDem}_{\text{run}} := \sum \text{demand}_{\text{run}} \cdot 60\text{s}$$

$$\text{DayDem} = \begin{pmatrix} 6.283 \\ 6.165 \\ 11.332 \\ 15.541 \\ 13.242 \\ 9.489 \end{pmatrix} \cdot \text{kWh}$$

The above vector is a list of total Day Demand for each run, 1-6.

The above value is the total energy generated by the PV panels during the day.

Overall net excess generation for the day, based on day generation and day demand, for each run.

$$\text{DayNetGen}_{\text{run}} := \text{DayPV\_clear} - \text{DayDem}_{\text{run}}$$

$$\text{DayNetGen} = \begin{pmatrix} 1.123 \\ 1.242 \\ -3.926 \\ -8.135 \\ -5.836 \\ -2.083 \end{pmatrix} \cdot \text{kWh}$$

Net generation is between 1kWh (positive, runs 1 and 2) to a deficit of 8kW (run 4).

Calculating another parameter, "DayNetExcess", from the sum of Excess minus Deficit for the day, for each run.

$$\mathrm{DayNetExcess}_{\mathrm{run}} := \mathrm{DayExcessE}_{\mathrm{run}} - \mathrm{DayDeficitE}_{\mathrm{run}}$$

$$\mathrm{DayNetExcess} = \begin{pmatrix} 1.123 \\ 1.242 \\ -3.926 \\ -8.135 \\ -5.836 \\ -2.083 \end{pmatrix} \cdot \mathrm{kWh}$$

For every run 1 to 6, "DayNetGen" is the same as "DayNetExcess"

This fact corroborates the above calculations.

6. Defining other parameters of interest

The sum of net generation (and excess) for all 6 runs is:-

$$\mathrm{SumDayNetGen} := \sum \mathrm{DayNetGen} \qquad \mathrm{SumDayNetExcess} := \sum \mathrm{DayNetExcess}$$

$$\mathrm{SumDayNetGen} = -17.615 \cdot \mathrm{kWh} \qquad \mathrm{SumDayNetExcess} = -17.615 \cdot \mathrm{kWh}$$

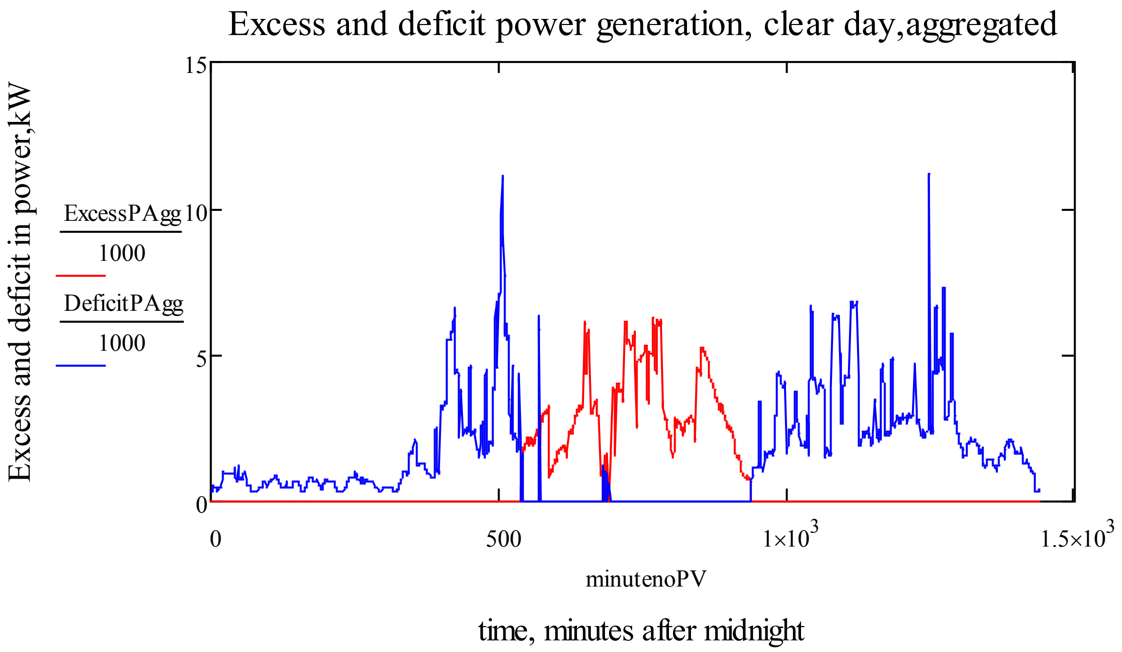
7. Looking at aggregated supply and demand for the collection of houses.

Calculating the excess and deficit in power at each one minute time step

$$\text{ExcessPAgg}_{\text{count}} := \left| \begin{array}{l} \left(\text{PV\_clear}_{\text{count}} \cdot \text{runs} - \text{aggdemand}_{\text{count}}\right) \ \text{ if } \ \text{PV\_clear}_{\text{count}} \cdot \text{runs} \geq \text{aggdemand}_{\text{count}} \\ 0 \ \text{ otherwise} \end{array} \right.$$

$$\text{DeficitPAgg}_{\text{count}} := \left| \begin{array}{l} \left(\text{aggdemand}_{\text{count}} - \text{PV\_clear}_{\text{count}} \cdot \text{runs}\right) \ \text{ if } \ \text{aggdemand}_{\text{count}} \geq \text{PV\_clear}_{\text{count}} \cdot \text{runs} \\ 0 \ \text{ otherwise} \end{array} \right.$$

The PV term is multiplied by the number of runs, in this case 6, because all the houses modelled in runs 1-6 would have their own generation.



$$\text{DayExcessAgg} := \sum_{\text{count}} \left(\text{ExcessPAgg}_{\text{count}} \cdot 60\text{s}\right)$$

$$\text{DayDeficitAgg} := \sum_{\text{count}} \left(\text{DeficitPAgg}_{\text{count}} \cdot 60\text{s}\right)$$

Displaying excess and deficit energy for the aggregated demand for the day:-

$\text{DayExcessAgg} = 20.024 \cdot \text{kWh}$

$\text{DayDeficitAgg} = 37.639 \cdot \text{kWh}$

And displaying per house aggregated excess and deficit energy for the day

$$\mathrm{DayExAggPH} := \frac{\mathrm{DayExcessAgg}}{\mathrm{runs}} \qquad \mathrm{DayExAggPH} = 3.337 \cdot \mathrm{kWh}$$

$$\mathrm{DayDefAggPH} := \frac{\mathrm{DayDeficitAgg}}{\mathrm{runs}} \qquad \mathrm{DayDefAggPH} = 6.273 \cdot \mathrm{kWh}$$

These day total aggregated per household excesses and deficits (based on aggregate demand), of 3.3kWh and 6.3kWh respectively, are smaller than the mean single house day excess and deficit: 4.4kWh and 7.5kWh.

Whether this difference is significant is not evaluated here.

Check: adding aggregate demands and generation

$$\mathrm{DayAggNetExcess} := \mathrm{DayExcessAgg} - \mathrm{DayDeficitAgg}$$

$\mathrm{DayAggNetExcess} = -17.615 \cdot \mathrm{kWh}$ displaying result

Comparing with sum of net generation, and net excess, over the day (calculated above, displayed below).

$$\mathrm{SumDayNetExcess} = -17.615 \cdot \mathrm{kWh}$$

$$\mathrm{SumDayNetGen} = -17.615 \cdot \mathrm{kWh}$$

All these values are the same. This fact corroborates the calculations.

APPENDIX 10 CALCULATION OF EXCESSES AND DEFICITS, WHEN THERE IS STORAGE: EXAMPLE MATHCAD SHEET "BATTERY CALCULATOR"

Calculation of power and energy transfers, in houses where there is storage (batteries)

$\text{ORIGIN} := 1$ sets the first value in any table or vector to one (default is zero).

1 Importing data.

First, importing csv files of values of excesses and deficits in power, in W calculated at each time step, by mathcad sheet Maincalc2. *[file names visible in Mathcad]*

$\text{ExP} :=$

$\text{DefP} :=$

Importing one column from PV generation data for the minute counter

$\text{minuteno} :=$

reading only the first column of data, which carries the minute counter data

Checking this minuteno counter is correct, by displaying minimum and maximum values, and number of rows.

$\min(\text{minuteno}) = 1$ $\text{length}(\text{minuteno}) = 1440$ $\text{rows}(\text{minuteno}) = 1440$

These are unitless data. Next, they are assigned units of power and energy, to convert back to the values they had on Mathcad sheet Maincalc.

$\text{DeficitP} := \text{DefP} \cdot 1\text{W}$

$\text{ExcessP} := \text{ExP} \cdot 1\text{W}$

Defining units kWh $\text{kWh} := 1000 \cdot 3600\text{J}$

Defining count of minutes over 24 hours $\text{count} := 1..144$

Defining runs (of the demand model): 1 run for each individual house, here 6 houses

$\text{run} := 1..$ $\text{runs} :=$

2 Defining power constraints of battery system

At each time step, the energy that can go into the battery is the "excess" (energy generated - demand) at that timestep, up to the max charge rate of the battery.

The power that can be drawn from the battery is "deficit" (demand - energy generated) up to max discharge rate of battery.

(The actual ability to charge or discharge will also depend on the state of charge ("SOC") of the battery, which is discussed later.)

Choosing arbitrary 1kW limits on charging and 2kW on discharging, to test the programme:-

$$\mathrm{Powertobattmax} := 1\mathrm{kW}$$

$$\mathrm{Powerfrombattmax} := 2\mathrm{kW}$$

AvailPtobatt is the excess generated power at that timestep, within charge rate constraints, that could be delivered to battery. DemPfrombatt is the deficit in power (i.e. load>generation) which could be drawn from battery, within discharge rate constraints. Neither parameter ("AvailPtobatt" nor "DemPfrombatt") take into account the state of charge of the battery.

$$\mathrm{AvailPtobatt}_{\mathrm{count},\mathrm{run}} := \left| \begin{array}{l} \mathrm{ExcessP}_{\mathrm{count},\mathrm{run}} \ \text{ if } \ \mathrm{ExcessP}_{\mathrm{count},\mathrm{run}} \le \mathrm{Powertobattmax} \\ \mathrm{Powertobattmax} \ \text{ otherwise} \end{array} \right.$$

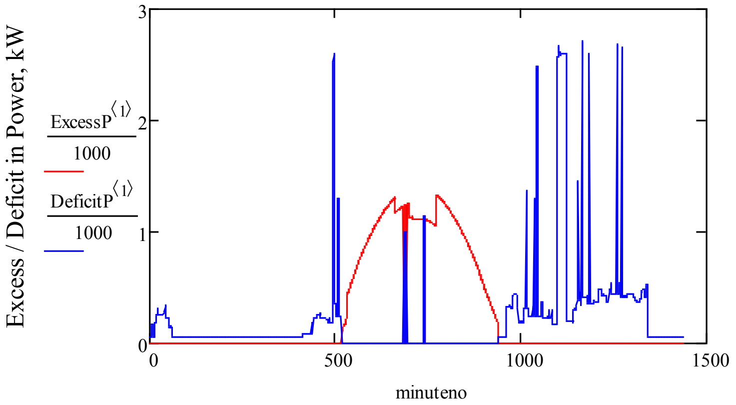
$$\mathrm{DemPfrombatt}_{\mathrm{count},\mathrm{run}} := \left| \begin{array}{l} \mathrm{DeficitP}_{\mathrm{count},\mathrm{run}} \ \text{ if } \ \mathrm{DeficitP}_{\mathrm{count},\mathrm{run}} \le \mathrm{Powerfrombattmax} \\ \mathrm{Powerfrombattmax} \ \text{ otherwise} \end{array} \right.$$

Below, the excess and deficit in power generation / demand is shown graphically for each run.

Graphs are also shown for the rate at which battery could be charged / discharged, within power constraints (but not including state of charge constraints here).

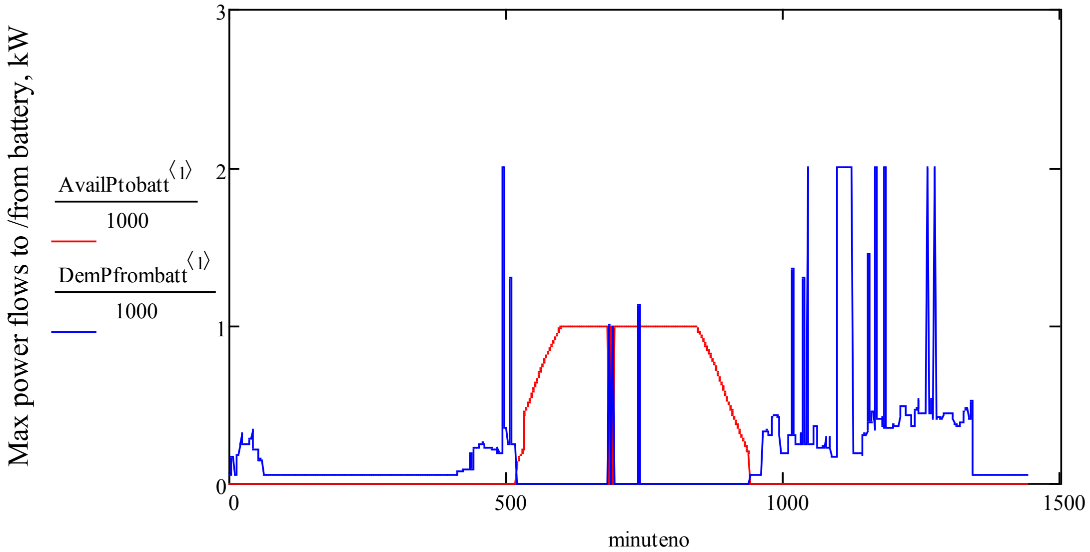
The run number is stated in the superscript (run number).

Excess and Deficit in Power generated, Run 1



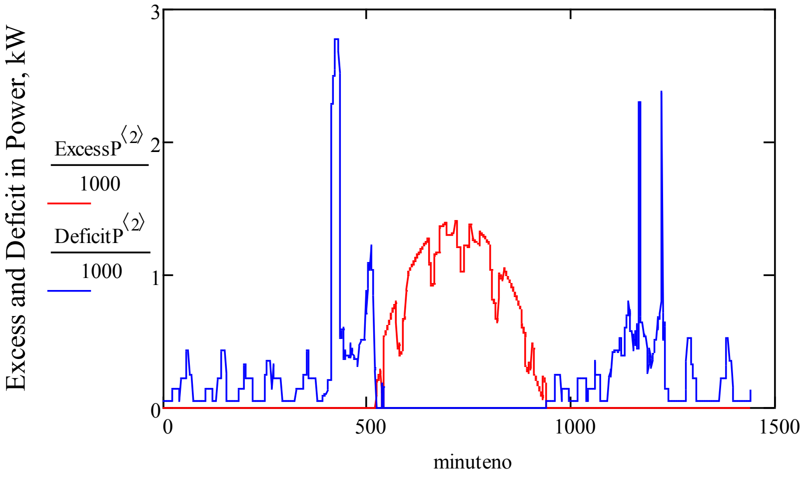
Time, minutes from midnight

Excess & Deficit in Power within battery power limits, Run 1



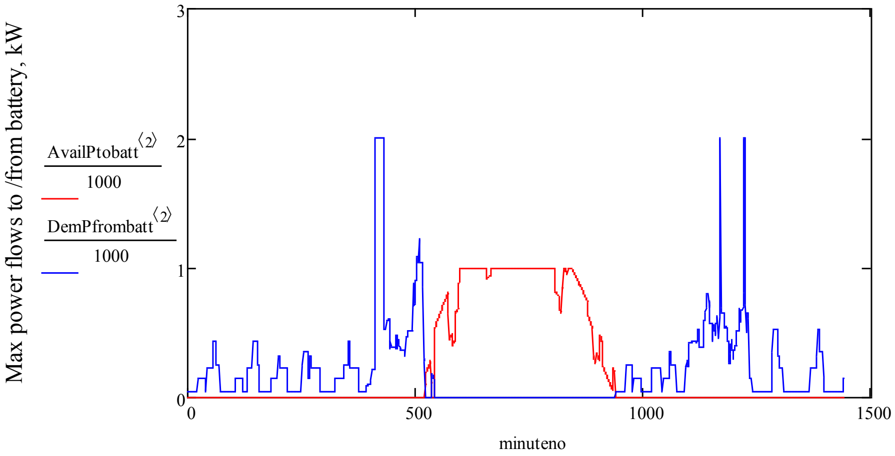
Time, minutes from midnight

Excess and Deficit in Power generated, Run 2



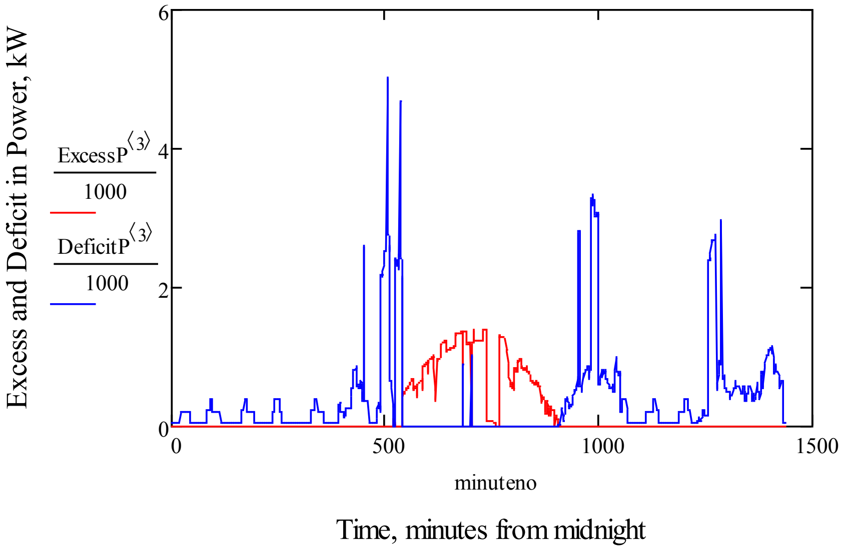
Time, minutes from midnight

Excess & Deficit in Power within battery power limits, Run 2

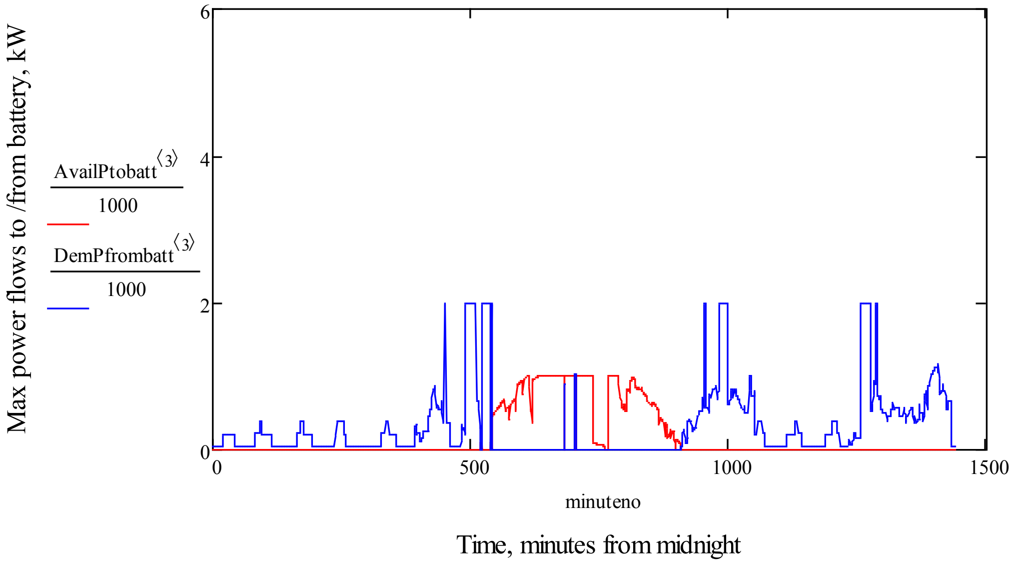


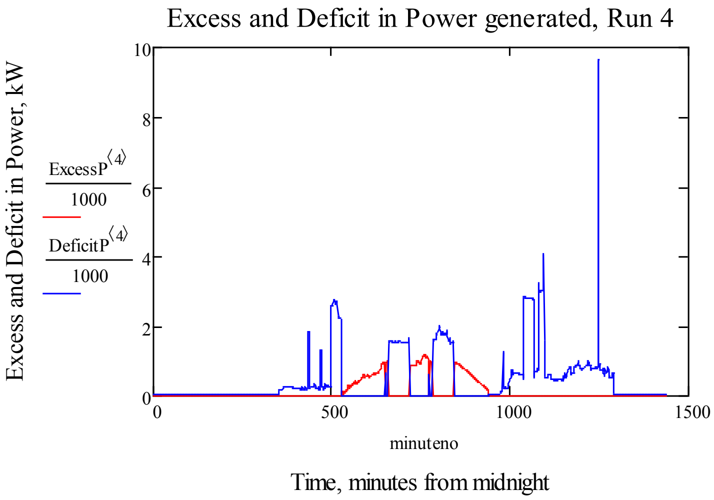
Time, minutes from midnight

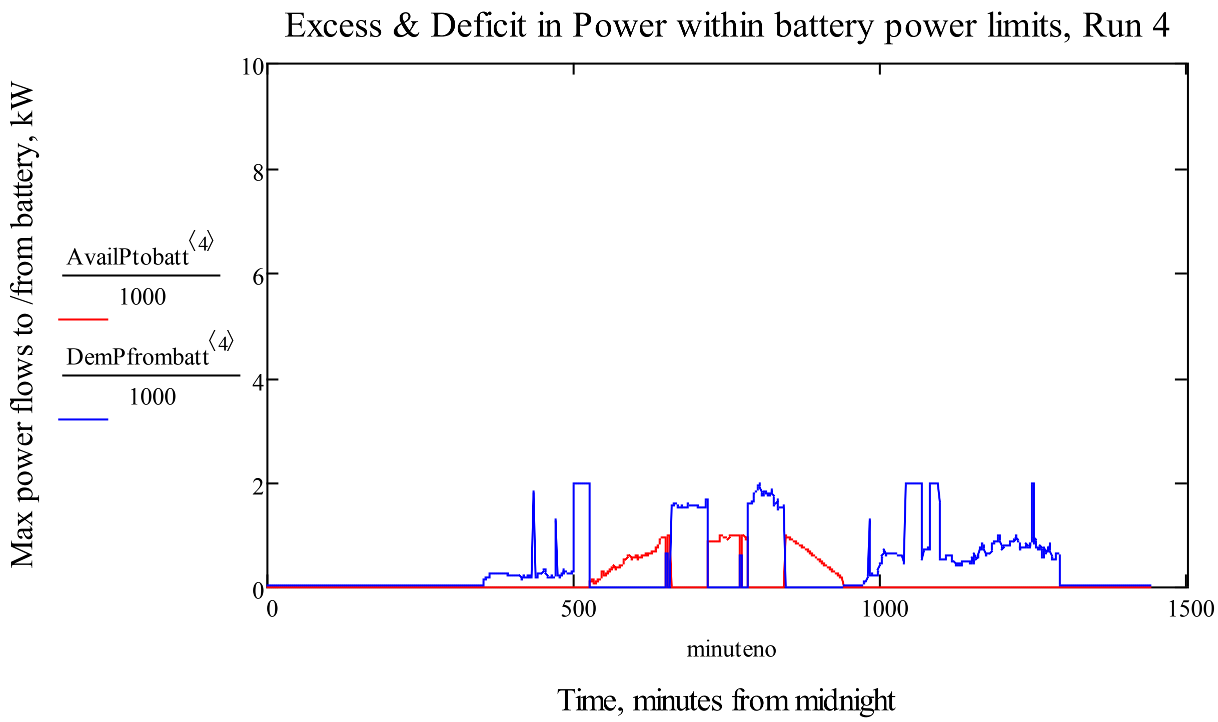
Excess and Deficit in Power generated, Run 3

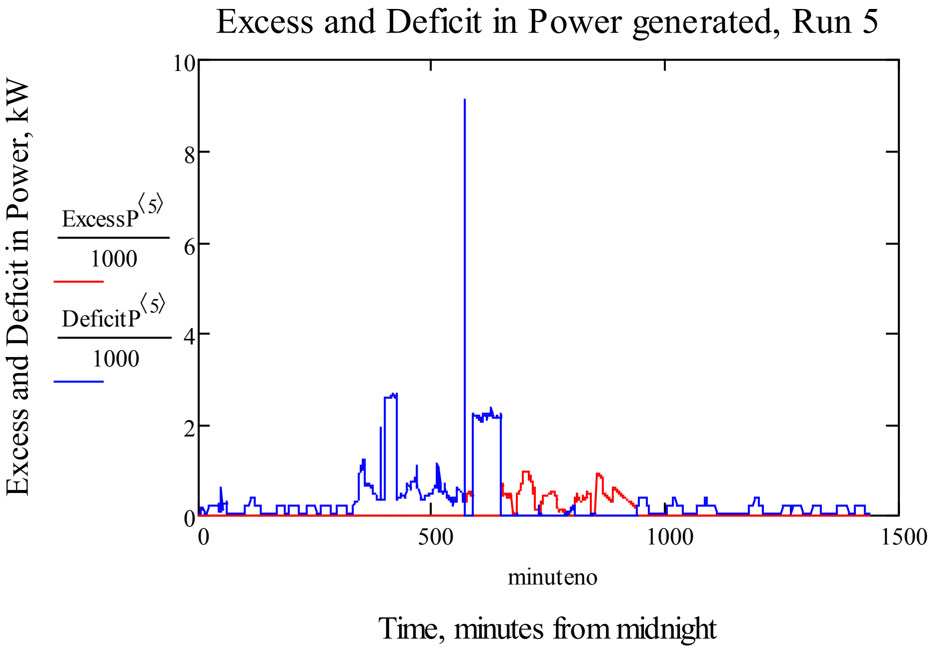


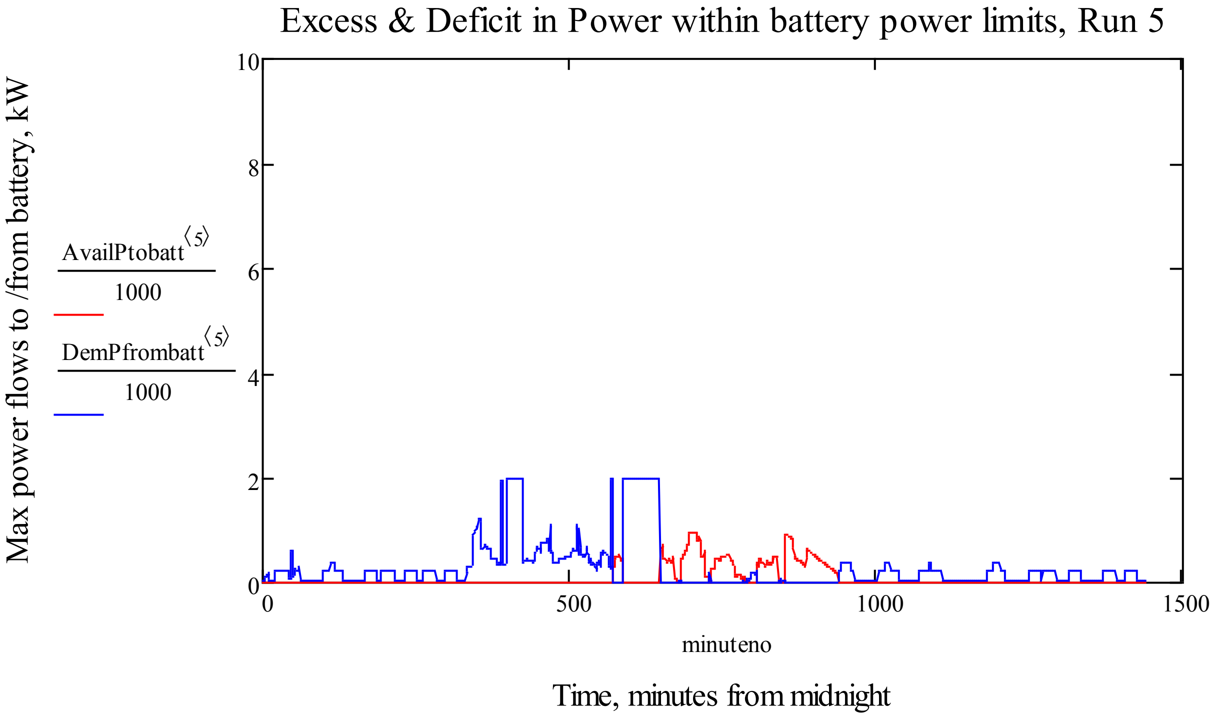
Excess & Deficit in Power within battery power limits, Run 3

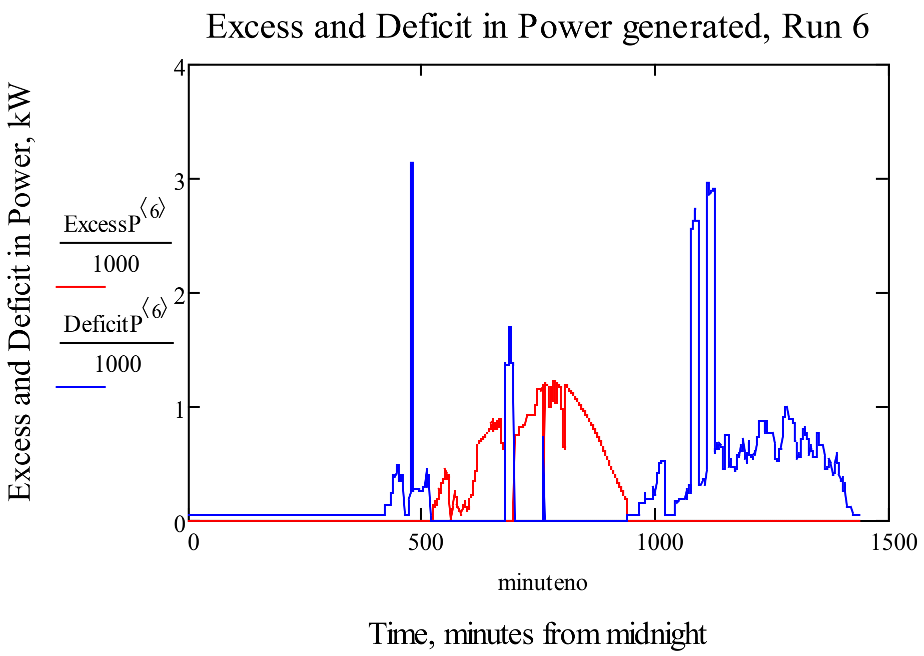



Excess and Deficit in Power generated, Run 4
Excess and Deficit in Power, kW
$\frac{ExcessP^{\langle 4\rangle}}{1000}$
$\frac{DeficitP^{\langle 4\rangle}}{1000}$
10
8
6
4
2
0
0
500
1000
1500
minuteno
Time, minutes from midnight

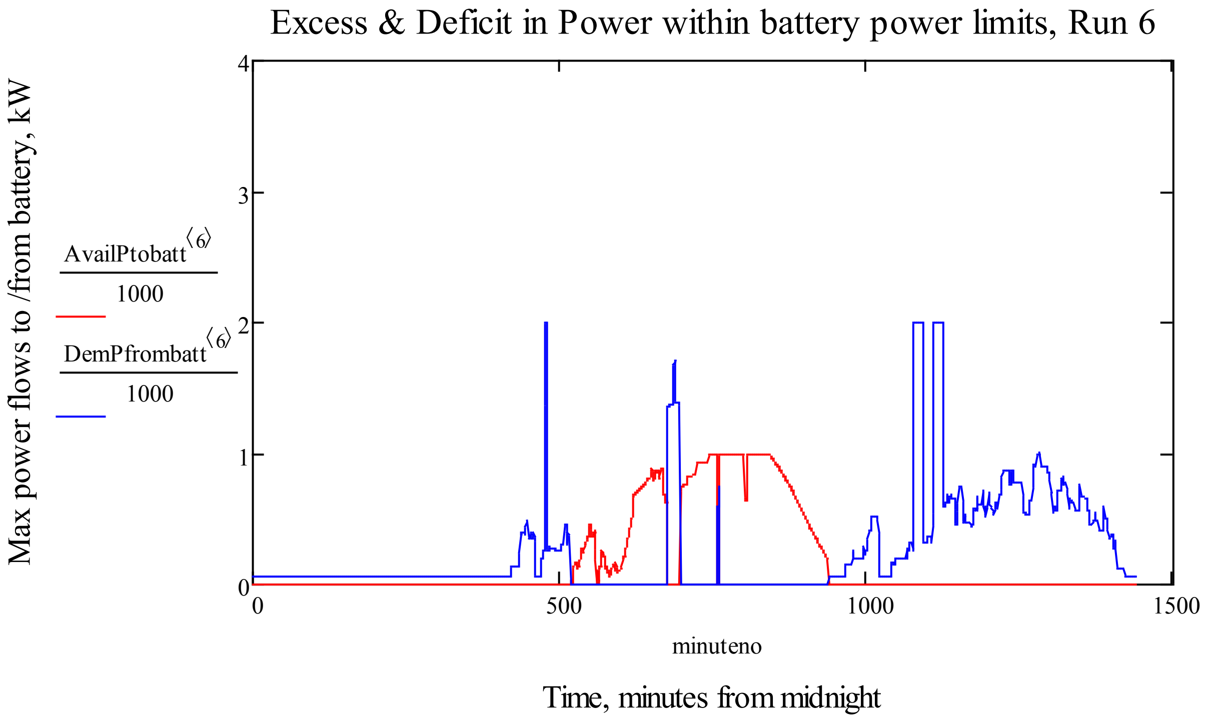

Excess & Deficit in Power within battery power limits, Run 4
Max power flows to /from battery, kW
$\frac{AvailPtobatt^{\langle 4\rangle}}{1000}$
$\frac{DemPfrombatt^{\langle 4\rangle}}{1000}$
10
8
6
4
2
0
0
500
1000
1500
minuteno
Time, minutes from midnight


Excess and Deficit in Power generated, Run 5
Excess and Deficit in Power, kW
$\frac{ExcessP^{\langle 5 \rangle}}{1000}$
$\frac{DeficitP^{\langle 5 \rangle}}{1000}$
10
8
6
4
2
0
0
500
1000
1500
minuteno
Time, minutes from midnight


Excess & Deficit in Power within battery power limits, Run 5
Max power flows to /from battery, kW
$\frac{AvailPtobatt^{\langle 5 \rangle}}{1000}$
$\frac{DemPfrombatt^{\langle 5 \rangle}}{1000}$
10
8
6
4
2
0
0
500
1000
1500
minuteno
Time, minutes from midnight



Excess and Deficit in Power generated, Run 6



Excess & Deficit in Power within battery power limits, Run 6

3.To calculate the energy the battery may be able to receive or deliver, based on its State of Charge (SOC)

SOC = state of charge of battery, between 0 and 1

$\text{capacity} := 4\text{kWh}$

Capacity of battery, i.e. the quantity of electrical energy it stores when fully charged.

$\text{maxcharge} := \text{capacity}$

The maximum desired state of charge of the battery may be set at its capacity, or a lower value. In this case, the maximum "charge" (energy) is set at equal to the capacity.

$\text{mincharge} := \text{capacity} \cdot ($

Similarly, the minimum desired charge may be higher than zero. Initially, here, the minimum charge is set at zero.

Some losses in energy during charge and discharge are inevitable. Here the efficiency of the battery system is defined.

$\text{Effbatt} := 0.81$

$\sqrt{\text{Effbatt}} = 0.9$

In calculations which follow, it is assumed that losses occur equally during charging and discharging. Thus, the square root of the battery efficiency, displayed here, is used in calculation. (Losses could alternatively be assigned unequally, or entirely to either charging or discharging.)

$\text{SOC}_{1,\text{run}} := 0.25$

Here the initial state of charge, at minute number 1, for each run, is defined.

$\text{charge}_{1,\text{run}} := \text{SOC}_{1,\text{run}} \cdot \text{capacity}$

$$\text{charge}_{1,\text{run}} = \begin{array}{|r|}\hline 1 \\ \hline 1 \\ \hline 1 \\ \hline 1 \\ \hline 1 \\ \hline 1 \\ \hline \end{array} \cdot \text{kWh}$$

Thus, the energy stored is the capacity times the state of charge, defined here.

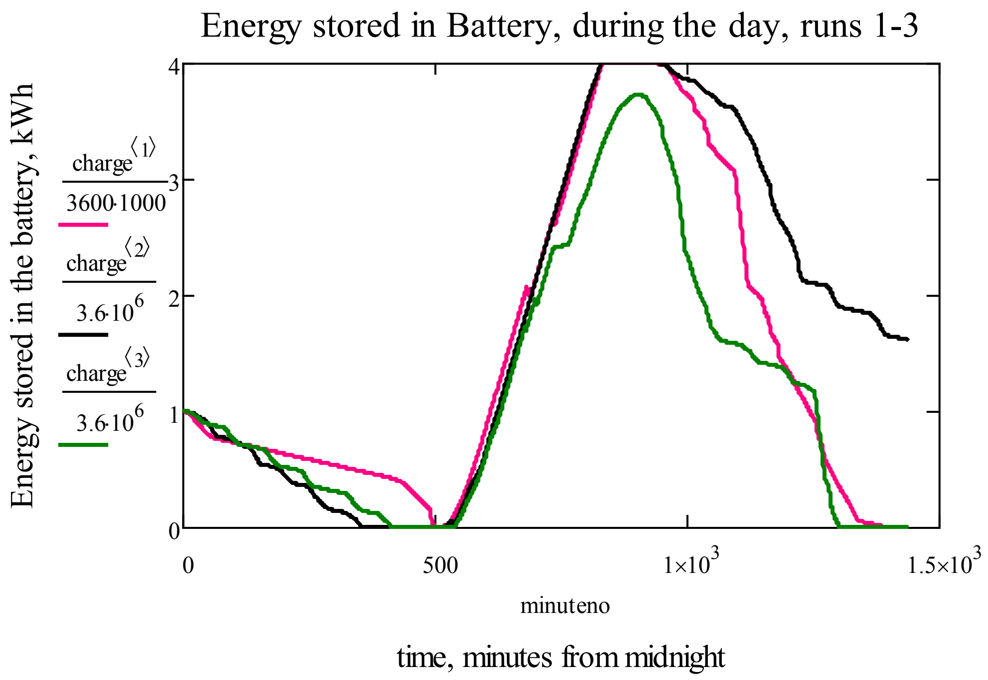
The initial state of charge for all 6 runs is displayed here.

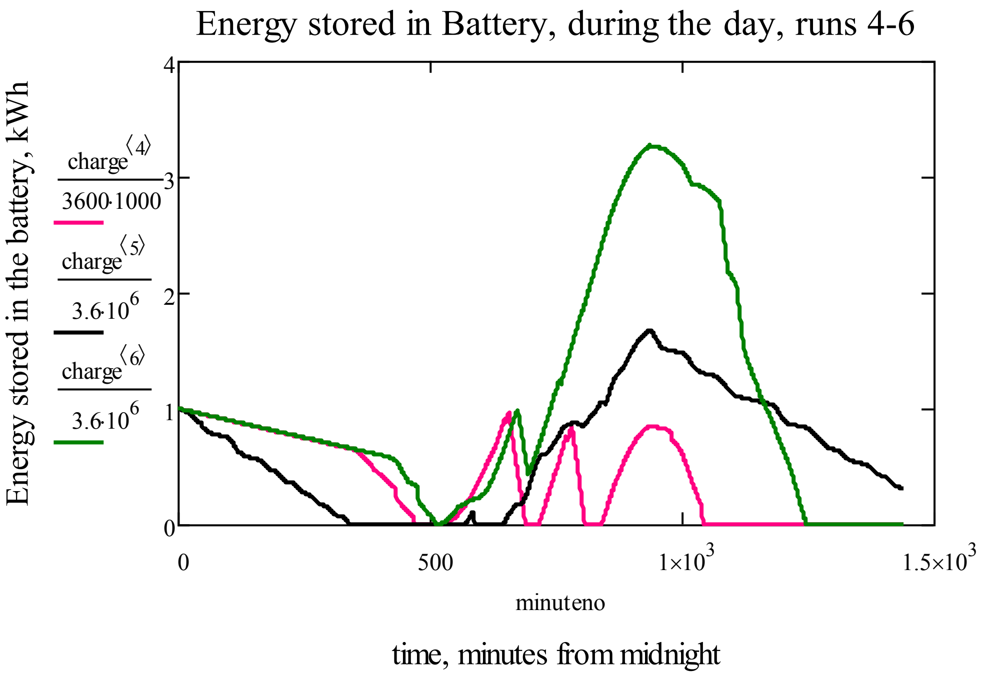
4. To define the charge (energy) stored in the battery at each timestep, the algorithm below sets limits: charge cannot exceed the maximum allowed charge, or fall below the minimum allowed charge (defined above). Between these limits, the charge at every time step is the charge it had at the previous timestep, plus / minus the power taken / delivered during that minute (with appropriate component of battery loss), * 60 seconds.

$$\text{AvailPtobatt}_{1441,\text{run}} := \text{AvailPtobatt}_{1,\text{run}} \qquad \text{DemPfrombatt}_{1441,\text{run}} := \text{DemPfrombatt}_{1,\text{run}}$$

$$\text{charge}_{\text{count}+1,\text{run}} := \left| \begin{array}{l} \text{maxcharge} \ \text{ if } \ \text{charge}_{\text{count},\text{run}} + \text{AvailPtobatt}_{\text{count}+1,\text{run}} \cdot 60\text{s} \cdot \sqrt{\text{Effbatt}} > \text{maxcharge} \\ \text{mincharge} \ \text{ if } \ \text{charge}_{\text{count},\text{run}} - \dfrac{\text{DemPfrombatt}_{\text{count}+1,\text{run}}}{\sqrt{\text{Effbatt}}} \cdot 60\text{s} < \text{mincharge} \\ \left[\text{charge}_{\text{count},\text{run}} + \left(\text{AvailPtobatt}_{\text{count}+1,\text{run}} \cdot \sqrt{\text{Effbatt}} - \dfrac{\text{DemPfrombatt}_{\text{count}+1,\text{run}}}{\sqrt{\text{Effbatt}}} \right) \cdot 60\text{s} \right] \ \text{ otherwise} \end{array} \right.$$

The results, i.e. the charge in kWh held in the battery, for each run, during the day, is shown graphically below.

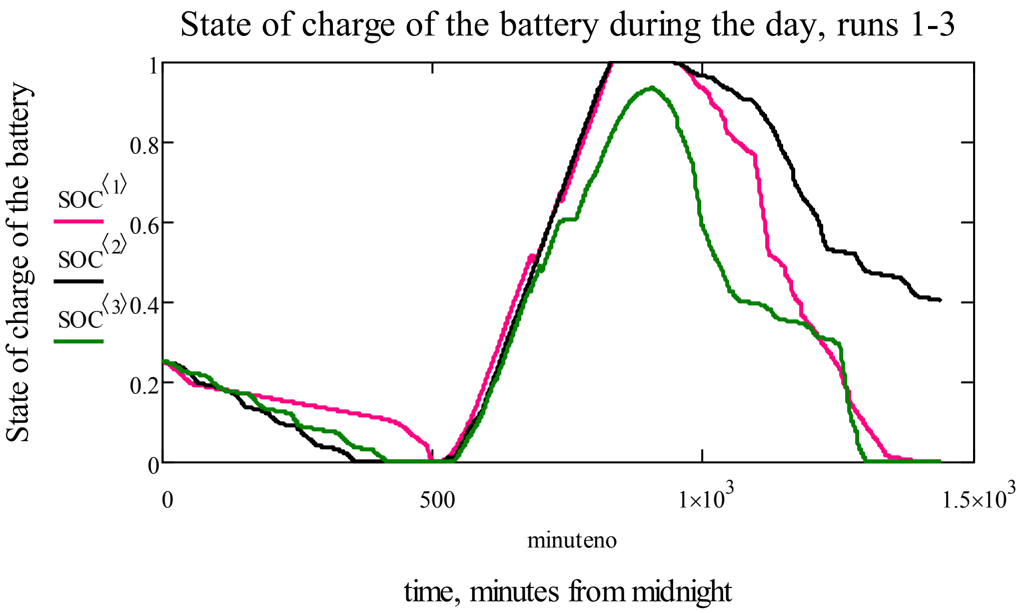


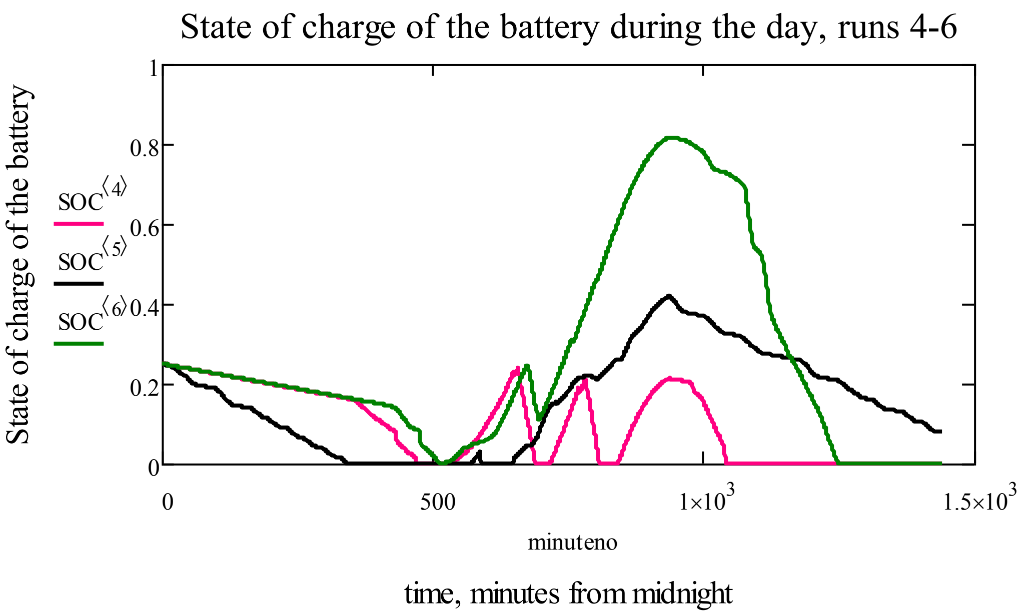


Comparing the above graphs with the power that can flow in and out of battery, these graphs look plausible.

The state of charge of the battery (a fraction between 0 and 1) has the same pattern as the charge (kWh) for each run

$$SOC_{count+1,run} := \frac{charge_{count+1,run}}{capacity}$$





5 To compute the energy flows into and out of the battery at each time step

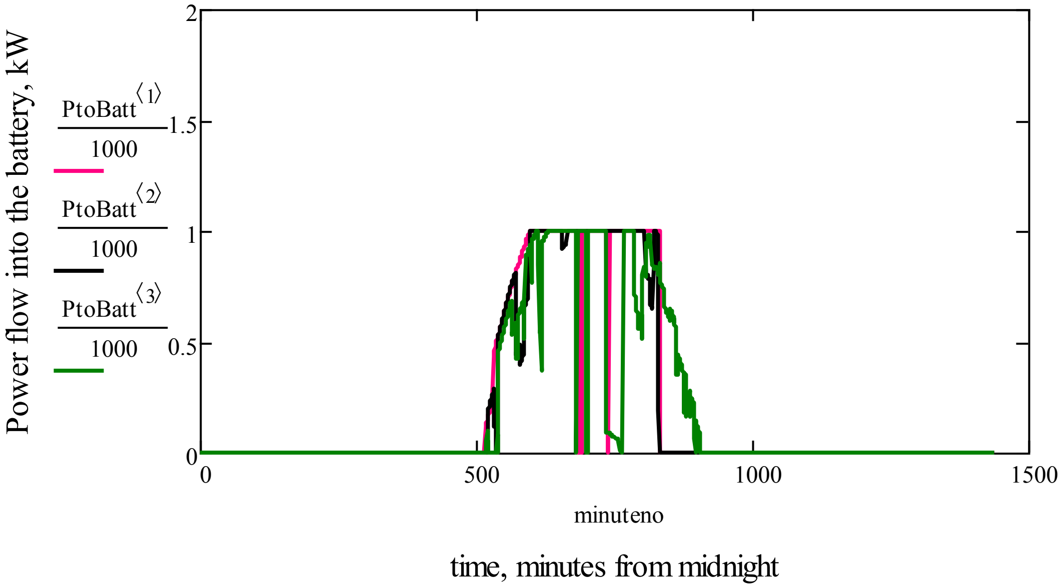
$$PtoBatt_{count+1,run} := \left| \begin{array}{l} \left(\dfrac{charge_{count+1,run} - charge_{count,run}}{\sqrt{Effbatt} \cdot 60s} \right) \text{ if } charge_{count+1,run} > charge_{count,run} \\ 0 \text{ otherwise} \end{array} \right.$$

$$PfromBatt_{count+1,run} := \left| \begin{array}{l} \left[\dfrac{\left(charge_{count,run} - charge_{count+1,run}\right) \cdot \sqrt{Effbatt}}{60s} \right] \text{ if } charge_{count,run} > charge_{count+1,run} \\ 0 \text{ otherwise} \end{array} \right.$$

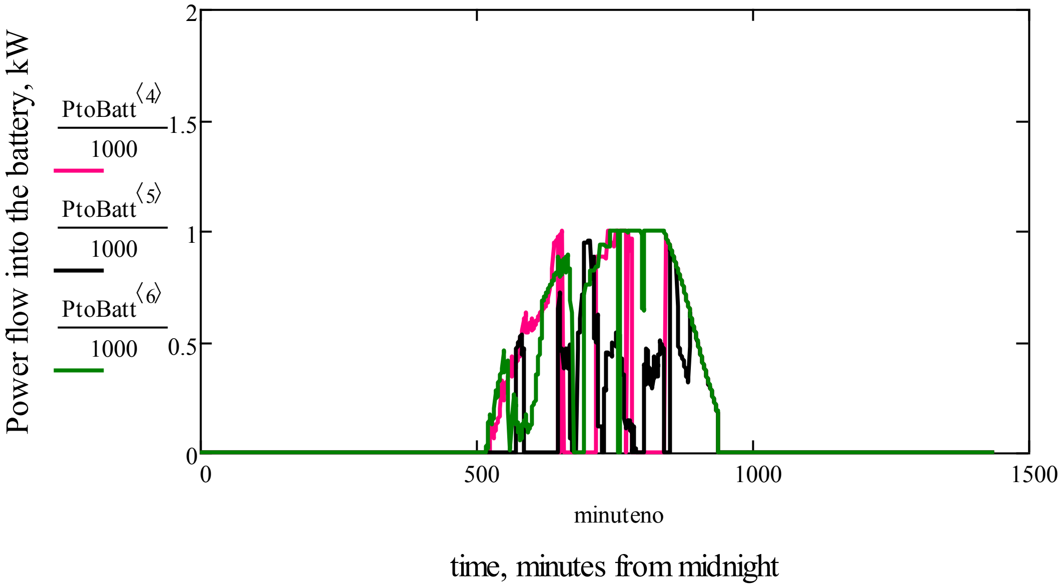
The above two algorithms evaluate the energy flow into and out of the battery at each time step, by comparing the charge (energy) content of the battery at the current and previous timesteps.

The "otherwise" statements ensure energy flows cannot be negative, i.e. charging is all described by "PtoBatt" and discharging is all described by "PfromBatt" at each minute, for each run.

Showing these graphically:-

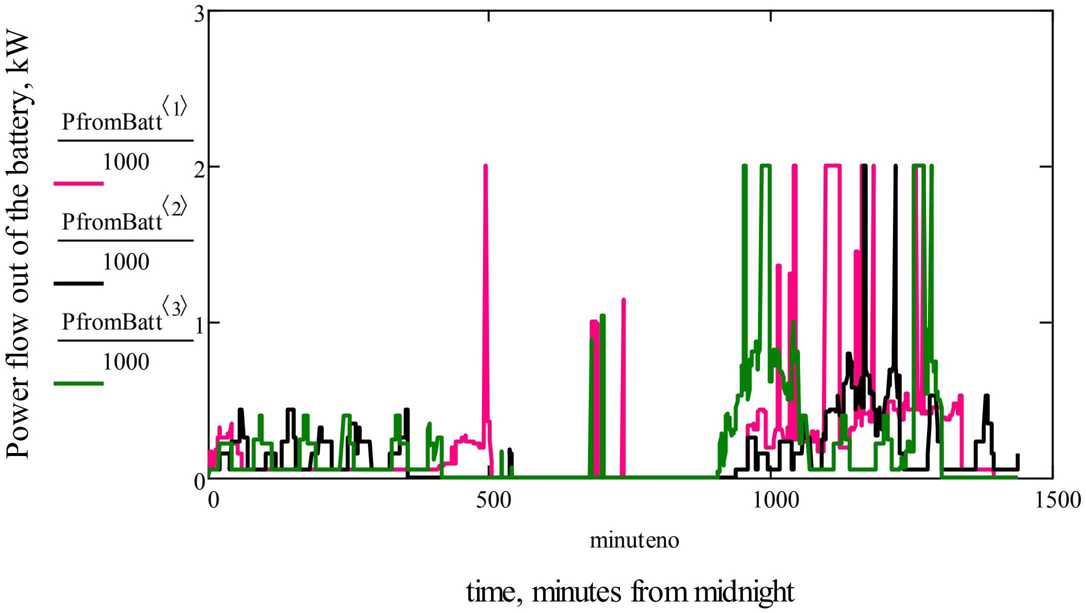


Energy flows into the Battery, during the day, runs 1-3

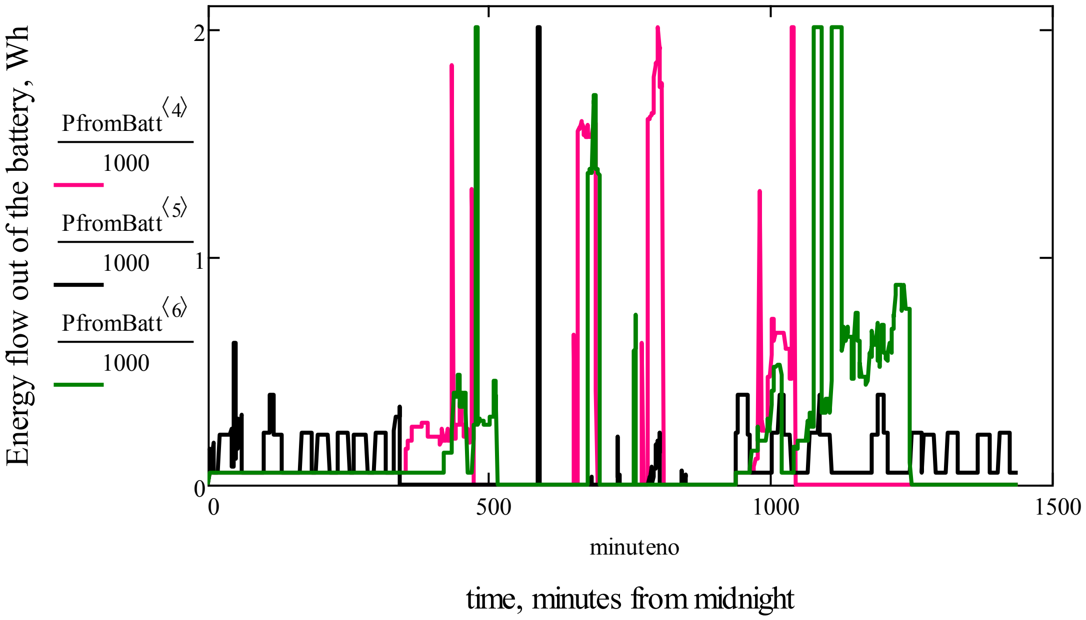


Energy flows into the Battery, during the day, runs 4-6

Energy flows from the Battery, during the day, runs 1-3



Energy flows from the Battery, during the day, runs 4-6



Energy flows in and out of the battery are limited by charging and discharging constraints of 1kW and 2kW.

There is some discharge early morning.

In the middle of the day, at most timesteps the battery is being charged, though there is discharge for short times when there are instances of high demand, most notably for runs 4 and 5.

There is considerable discharge in the evening.

Late evening discharge is limited by the battery state of charge for most of the runs

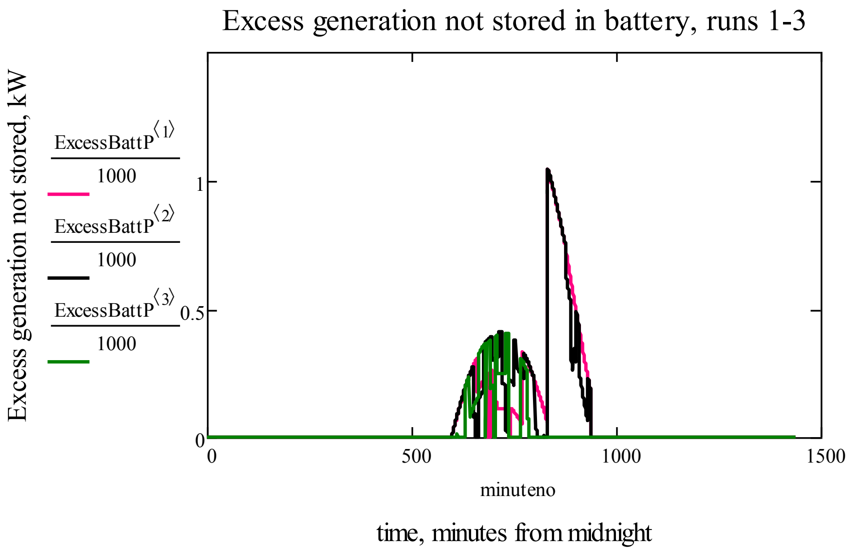
6. To compute the excess energy flows - both generation and demand - which exceeded battery constraints, at each time step

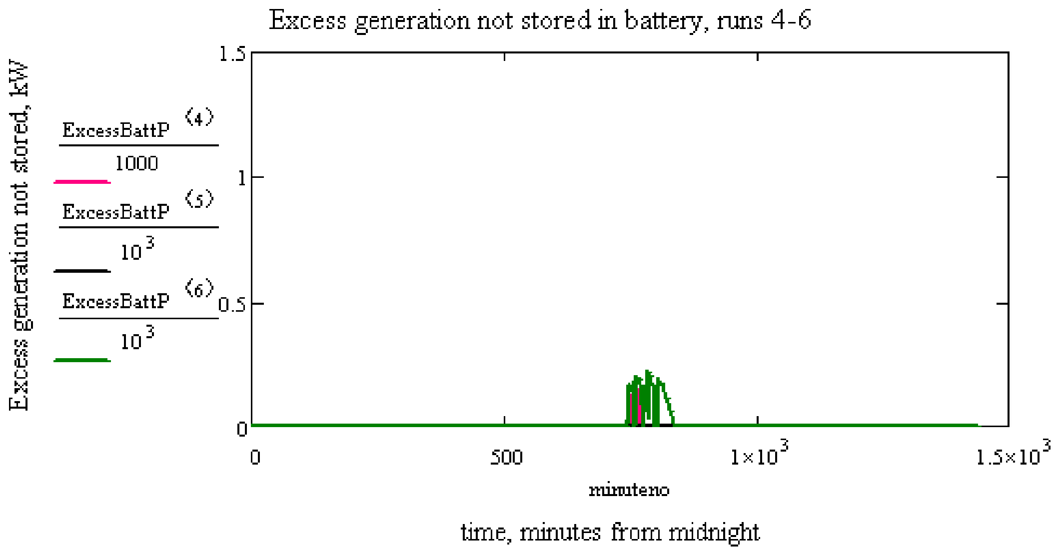
ExcessbattP is the excess power generation which was not stored in battery at that timestep because of battery power or capacity constraints.

DefbattP is deficit in power of system with batteries at a timestep: deficit in energy which was not provided by battery because of lack of stored energy or battery discharge constraints

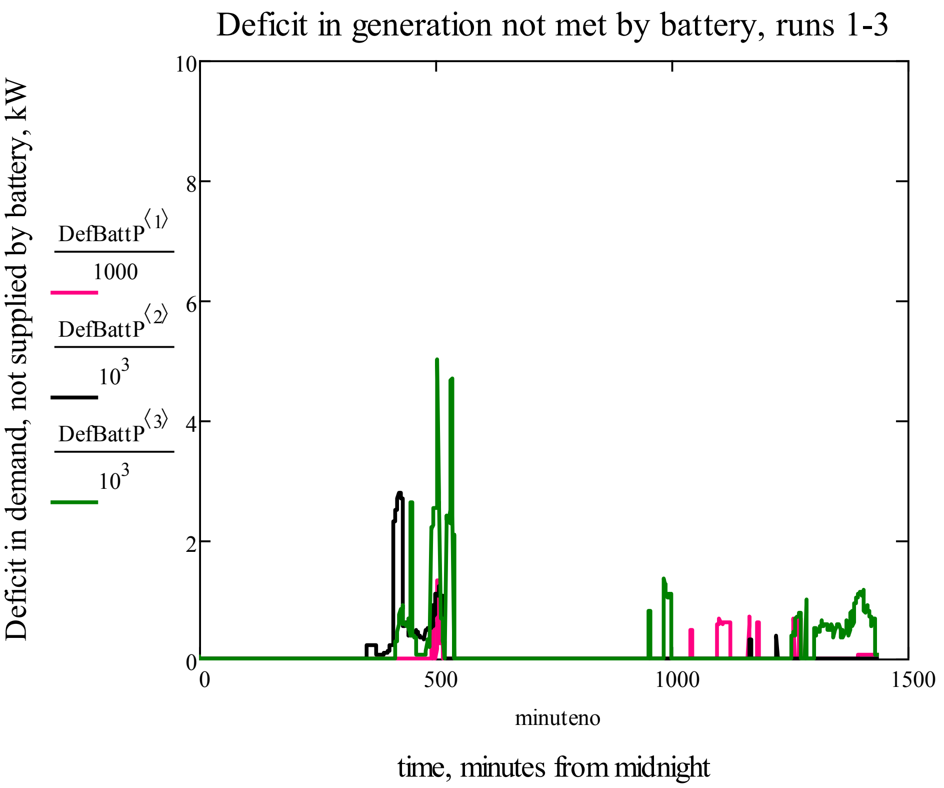
$$\mathrm{ExcessBattP}_{count,run} := \mathrm{ExcessP}_{count,run} - \mathrm{PtoBatt}_{count,run}$$

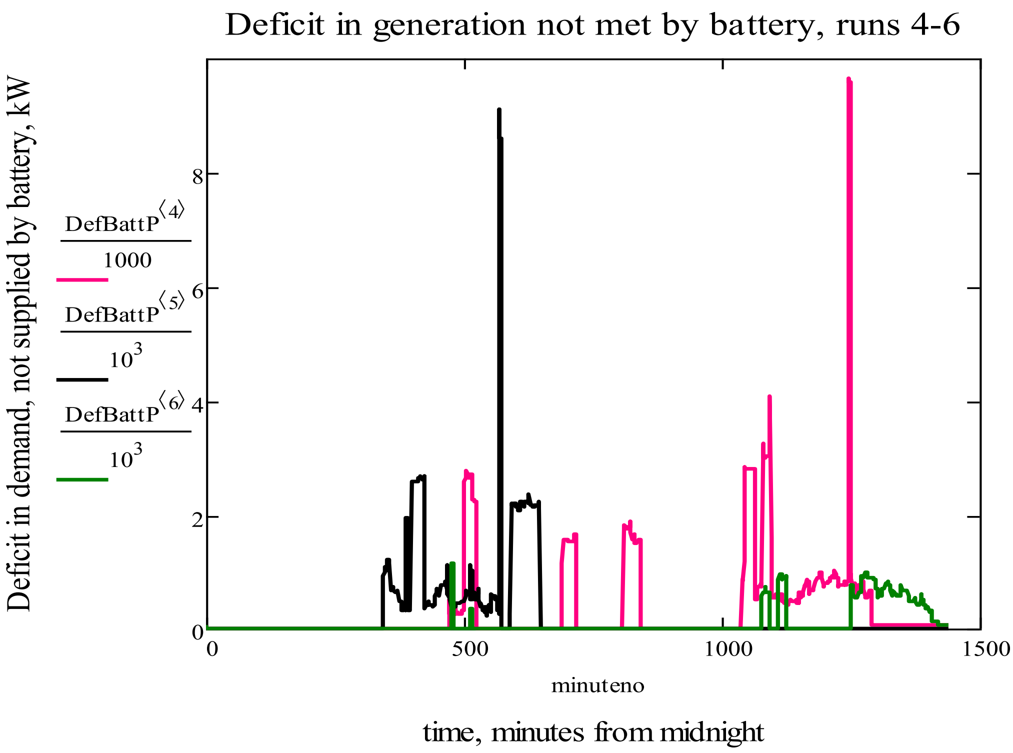
$$\mathrm{DefBattP}_{count,run} := \mathrm{DeficitP}_{count,run} - \mathrm{PfromBatt}_{count,run}$$





There is a small excess in the middle of the day, in all runs, due to charge rate constraints. In runs 1 and 2, the sudden rise around minute number 830 is because the battery is fully charged.





With a battery having a discharge constraint of 2kW, there are several occasions during the day when the battery cannot meet demand due to discharge limit being lower than the power demand.

8. <u>To evaluate the daily totals of excesses and deficits not met by the battery</u>

$$\mathrm{DayExcBattE}_{run} := \sum_{(count)} \left(\mathrm{ExcessBattP}_{count,run} \cdot 60s\right)$$

$$\mathrm{DayDefBattE}_{run} := \sum_{count} \left(\mathrm{DefBattP}_{count,run} \cdot 60s\right)$$

The above define the daily totals of excess generation and deficit in demand which were not met by the battery.

Displaying these totals below, for each run (listed for runs 1-6)

$\mathrm{DayExcBattE}_{run} =$

1.740
1.770
0.503
0.038
0.000
0.196

$\cdot \mathrm{kWh}$

$\mathrm{DayDefBattE}_{run} =$

0.598
1.923
4.337
7.849
5.604
2.194

$\cdot \mathrm{kWh}$

$$\mathrm{MeanDayExBatt} := \frac{\sum \mathrm{DayExcBattE}}{\mathrm{runs}}$$

$$\mathrm{MeanDayDefBatt} := \frac{\sum \mathrm{DayDefBattE}}{\mathrm{runs}}$$

$\mathrm{MeanDayExBatt} = 0.708 \cdot \mathrm{kWh}$ $\mathrm{MeanDayDefBatt} = 3.751 \cdot \mathrm{kWh}$

APPENDIX 11 CHECKS MADE ON CALCULATIONS

Many checks were made on the model while it was under development. The main ones are described below.

Solar data

The data tables were inspected, and viewed graphically, to verify that the following were the same for both original PVGIS data, and manipulated datasets:

- the peak values,
- times ("minute numbers") at which the first and last data points of irradiation occur (i.e. dawn and dusk), and
- general shape of the irradiation curves

Examples of Mathcad sheets performing this calculation are appended (Appendix 2 and 3).

Calculation of electricity generated by PV panels, for a given building

Calculated electrical generation day totals were "back calculated" to obtain insolation, in Wm^{-2}. These totals were compared with a separate calculation, in an Excel workbook, of day total irradiation per square metre of inclined surface ("roof"), and horizontal surface beneath it ("floor") calculated directly from the PVGIS data. The totals for January, on average, cloudy and clear days are compared, they all agree to 2 significant figures. Small differences are expected because of different interpolation methods. This agreement was taken as corroboration that the calculations are likely to be correct.

Full details are described in Mathcad sheet "Electricity In" which is in Appendix 5.

Demand data

Datasets were inspected to ensure every minute number had a value for demand, and that the total number of data points was 1440 (corresponding to 24 hours, multiplied by 60 minutes in an hour). The data were examined graphically to ensure the demands were different for every run.

"Main calculation": deficits and excesses in electrical generation, *where there is no electrical storage*

Mathcad sheet "Main calculator", appended in APPENDIX 6, takes data for electrical demand, and generation from the PV panels, and calculates the excess and deficit in electrical generation / demand at each one-minute time step, for each run. The worksheet then calculates the daily total of excess and deficit for each run. This is initially performed for one type of day (e.g. January, clear) and later repeated for others.

1. A check of the both electrical generation and demand files was done to check the minute number counters were the same.
2. PV generation: data are displayed graphically, and the data file interrogated for a few sample values, and compared to the original data file, to ensure the data have been correctly imported.
3. Demand data are displayed graphically, and a few values checked against the original demand data file, to ensure the data have been correctly imported.
4. Excess and deficit power results calculated by the worksheet are examined.
    a. The initial few minutes of data are compared to demand data, to ensure there deficits are all equal to the demands (as it is night and so there is no generation) and excesses are all zero.
    b. For all runs there are peaks in deficit, many short in duration, in the morning and evening; in some runs there are deficit peaks also during the day. Some were checked against demand data and found to be consistent.
    c. In all cases there is a broad peak in excess in the middle of the day, consistent with solar generation, which is interrupted / reduced in magnitude for short durations by demand. It was noted the maximum value of excess generation is at or slightly below the maximum value of total generation, which is correct when there is little or no demand (which was the case for some runs).
    d. Selected points of interest were examined in detail, e.g. for "Main Calculator" ("scenario 1") run 1, minute number 682-695, and 735-745, show 3-minute peaks in deficit interrupting a broad peak of excess generation. Excess in generation was observed to be zero at all time-steps having non-zero values of deficit, and vice versa, which is correct. These peaks in demand were checked against original demand data, and were found to be consistent.
    e. Comparing different totals for the day
        i. The data series for the excesses and deficits in generation, at each minute, and for each run, were each exported to a data file. A manual calculation on the exported data computed day-totals for excess and deficits in generation for each run, and for all runs. The Mathcad

worksheet computed totals of day excess and deficits. These totals, calculated by different means, agreed.

   ii. In the Mathcad sheet, the day total for demand (for each run), and generation, are evaluated. It is observed that some runs have less demand than generation, and some have more. These totals were used to compute a "day net generation" for each run. Separately, the "day net excess", defined as the "day excess" minus "day deficit", was evaluated for each run. The "day net generation" and "day net excess" were found to be identical for each run (minus 17.6kWh, i.e. a deficit).
   iii. Considering an aggregation of all the demands, generation and storage, the excesses and deficits (for all runs aggregated) were evaluated for each minute, and the day total. The day total aggregated excess and deficit per household (3.3kWh and 6.2kWh respectively), were found to be a little lower than the average (arithmetic mean) of the day totals of excesses and day deficits for the six individual runs (4.5kWh and 7.4kWh respectively). This is as expected.
   iv. The day totals of excess and deficit for all runs aggregated (discussed in point 4. f. iii above) were used to evaluate day total for aggregated net generation (defined as "aggregated day excess "minus "aggregated day deficit"). This "day aggregated net excess" was found to be 17.6kWh, identical to the day totals of "day net generation" and "day net excess", as discussed above in point 4. f. ii. The agreement of all these day totals, computed differently, corroborates these calculations.

Further details are described in Mathcad sheet "Main calculator" in Appendix 6.

"Battery calculation": Calculating power transfers in houses *with* electrical storage
Mathcad sheet "Battery calculator" does the calculation. A copy is appended in Appendix 7.

Later versions of this calculation sheet incorporated calculations on aggregations of runs, as well as individual ones.

1. Excess and deficit in power generation were displayed graphically to ensure they were consistent with previously calculated values. They were compared graphically with the excess and deficits within battery power limits (maximum charge and discharge rates, defined in the worksheet). Viewing these together, the maximum power flows

to and from the battery for each run were observed to have the same basic pattern as the excess and deficit in generation, but were limited at the battery constraints. E.g. for most runs, maximum excess in generation was approximately 1.5kW, and the battery maximum charge rate of 1kW was set. Most run had instances of deficits of 3kW and more, but the maximum power the battery could deliver was set at 2kW.

2. The charge (in kWh) held within the battery is calculated at each time step. In the first scenario, the battery initially contains some charge, which is exhausted during the night and early morning for each run. The charge and State of Charge (SOC) of the battery during the day or each run was examined. Peaks and troughs were compared to events of excess and deficit in generation. The general shape of all the curves was consistent with the excess and deficits.
3. Energy flows in and out of the battery for each run were displayed graphically. They were compared with the curves for excesses and deficits in generation, and checked to ensure they complied with power (charge and discharge rate) constraints of the battery. It was also observed that energy delivered by the battery fell to zero at times when the SOC had fallen to zero, in several instances.
4. The algorithm computing energy flows into and out of the battery was tested on a separate Mathcad sheet, in which an initially empty battery received energy from generation for a single time-step, and later supplied a demand at two time steps only, to check that:
    a. Total energy supplied = total energy from generation * battery efficiency.
    b. Energy entered the battery at the rate of generation, and was later supplied by battery at a rate which met demand, while there was enough charge in the battery to do so. (Charge and discharge limits were set high, to avoid limiting this test.)
5. Excess generation not stored in the battery was shown graphically for the runs. It was observed that excesses were generally small, and consistent with power (charge rate) constraints of the battery. However for two runs, there was a sudden rise in excess in early afternoon, which corresponded to the battery being full and unable to accept more charge. Similarly, deficits in generation not met by the battery were shown graphically for the runs. There were spikes at times of high demand which exceeded the battery discharge constraint of 2kW. There were also numerous peaks at times when the battery was empty.

6. The time at which the battery reached a state of charge (SOC) of zero was interrogated for each run. Separately, a manual calculation of this time was performed, directly from data files containing data for demand (and for two runs, also data for deficit in generation not met by the battery). In all cases, the time to reach SOC was the same for both calculations.
7. At three selected minute numbers: 300, 500 and 700, all in the morning, the charge held in the battery, at each run, was interrogated from the Mathcad sheet. A separate manual calculation was performed directly from demand and deficit data for the early (minute number 300 and 500) time steps. The charge held in all cases agreed exactly, or within 0.002kWh. The small error was considered acceptable due to different calculation methods. Evaluating the charge held at minute number 700 is more complex as there is both generation and demand, some of which goes through the battery (and is subject to battery losses) and some of which does not. An approximate calculation achieved fairly good agreement for four of the six runs (and was not attempted for the other two). Considering the manual calculation attempts to calculate over the whole time in bulk, whereas the Mathcad sheet evaluates at every time step, some differences in results were expected, and these ones were considered acceptable.
8. Regarding timing of power flows, there are two choices:-
    a. All power flows, including in to and out of the battery, happen simultaneously, (with the state of charge the previous time-step being a factor in calculation), or
    b. Power flows in and out of battery occur one time step after demand / generation.

    Both options were examined, with several time-steps of varying generation or demand being interrogated in detail.

    a) Has the advantages that this is ideally what is desired, and it is assumed that batteries can respond quickly, i.e. in a time considerably less than the one-minute time-step, so this is the closest approximation. In the logic of these Mathcad sheets, the demand at the very first time step is not used in calculation, but all following demands are. The algorithm calculates charge in the battery up to time step 1441, one time-step after the end of the day. It is necessary to approximate power flows available to and from the battery at time step 1441, even though this value is not used.)

b) Has the advantage that it uses every single demand, including demand at the first time step, in calculations. In some systems, there may be a delay in response, and in such cases this approach may be applicable.

It was decided to use approach a) even though the omission of the demand at the first time step (Midnight) introduces an error, as the first demand appears as a deficit, even when the battery has enough charge to meet them. In the Richardson model, these demands were around 50W for most runs, and thus the magnitude of this error is modest (less than 1Wh for most runs). This error would thus not significantly affect results.

Check of initial results

After obtaining the first set of results, for scenario "urban1, 6 runs", all the data were checked to ensure that excesses and deficits all lay within the bounds of total generation and total demand; and that excesses were greater for clear >average>cloudy days, and deficits were greater for cloudy > average>clear days.

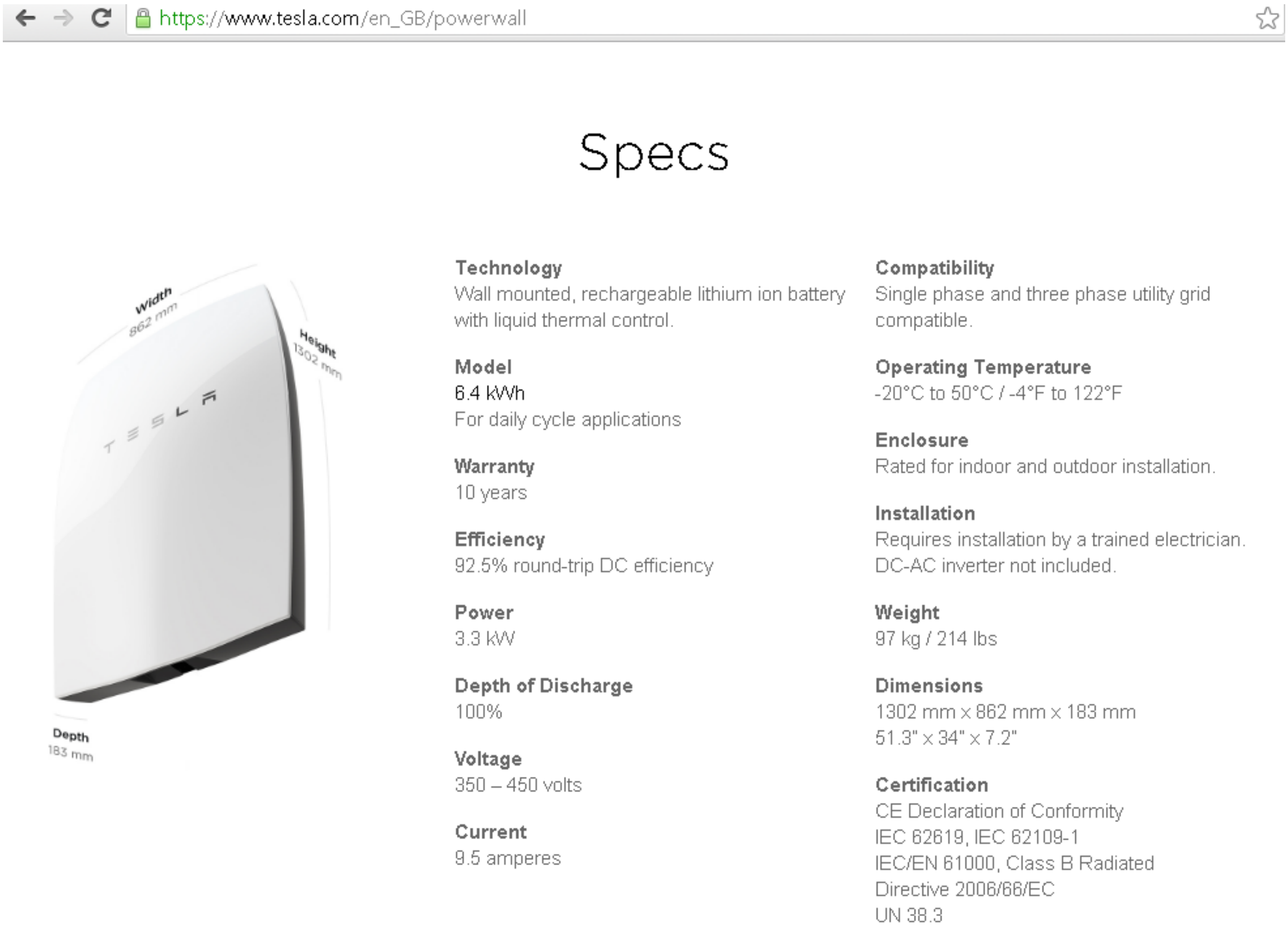
In a few cases, deficits were found to be slightly greater on "average" than "clear" days. Close inspection of the PVGIS data shows for a short time, around 1-2 hours, early morning and / or late evening (depending upon orientation) the insolation on cloudy and average days exceeds that on clear days, by around 100-200W. (It is not clear whether this is a real occurrence, or if it could be a small error in PVGIS. This was not investigated.) In some cases, where deficits occurred during these periods and not at other times of the day, this effect led to deficits on "average" days being less than on clear days, by up to around 0.3kWh.

Checks on macro which automated multiple runs of Richardson's demand model

The new macro was tested thoroughly before use. It was modified to alternatively display: external irradiance, active occupancy count, appliance ownership, total electrical demand for lighting, and total electrical demand for appliances, as well as total overall electrical demand. Runs were done for different months, and output values were checked to ensure the values and variations met expectations. This check was necessary to be sure that the new macro was successfully running all parts of the Richardson programme (i.e. running the lighting model;

calculating active occupant count, allocating appliances, and from these models, calculating electrical demands). In some runs of 100, numbers of runs having certain appliances were counted to ensure they conformed to expectations based on probability of ownership. For example, the default probability of storage heating is 2.6%: runs of 100 were found to have between 2 and 5 households with this item, which is as expected. The presence of an electric shower, default probability being 67%, was found to be between five and eight for every group of ten runs inspected, again as expected. It was thus concluded that the macro successfully ran all parts of the Richardson model, to the desired number of runs, and was suitable for use.

APPENDIX 12 TESLA POWERWALL BATTERY: Manufacturer's data



Specs

Technology
Wall mounted, rechargeable lithium ion battery with liquid thermal control.

Model
6.4 kWh
For daily cycle applications

Warranty
10 years

Efficiency
92.5% round-trip DC efficiency

Power
3.3 kW

Depth of Discharge
100%

Voltage
350 – 450 volts

Current
9.5 amperes

Compatibility
Single phase and three phase utility grid compatible.

Operating Temperature
-20°C to 50°C / -4°F to 122°F

Enclosure
Rated for indoor and outdoor installation.

Installation
Requires installation by a trained electrician. DC-AC inverter not included.

Weight
97 kg / 214 lbs

Dimensions
1302 mm x 862 mm x 183 mm
51.3" x 34" x 7.2"

Certification
CE Declaration of Conformity
IEC 62619, IEC 62109-1
IEC/EN 61000, Class B Radiated
Directive 2006/66/EC
UN 38.3

https://www.tesla.com/en_GB/powerwall


Width
860 mm
Height
1300 mm
Depth
180 mm
TESLA

Supplier's data

Available at: https://www.safeinstall.co.uk/tesla-powerwall-uk/

Tesla Powerwall Term's and Conditions – Warranty

- The battery shall have >85% of initial rated capacity at the earlier of:

– 4000 kwh of total discharge throughput (at the battery DC output) or,
– 2 years from the Delivery Date or,
– 3000 hours above 80% SOE

- The battery shall have >72% of the initial rated capacity at the earlier of:

– 9000 kwh of total discharge throughput (at the battery DC output) or,
– 5 years from the Delivery Date or,
– 7500 hours above 80% SOE

- The battery shall have >60% of the initial rated capacity at the earlier of:

– 18 kwh[2] [18,000kWh] of total discharge throughput (at the battery DC output) or,
– 10 years from the Delivery Date or,
– 15,000 hours above 80% SOE

The SOE (State of energy) is measured by testing the battery at an ambient air temperature of 25°C. The energy is measured at the 400V DC link when discharged at a rate of 3.3kW from 100% SOE.

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[2] Believed to be a mistake on the website. Correct value believed to be 18,000 kWh

APPENDIX 13 L G CHEM LITHIUM ION BATTERY: INFORMATION

A UK-based equipment supplier (Wind and Sun, http://www.windandsun.co.uk/) prints the following information on the above battery

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LG Chem RESU 6.4 EX

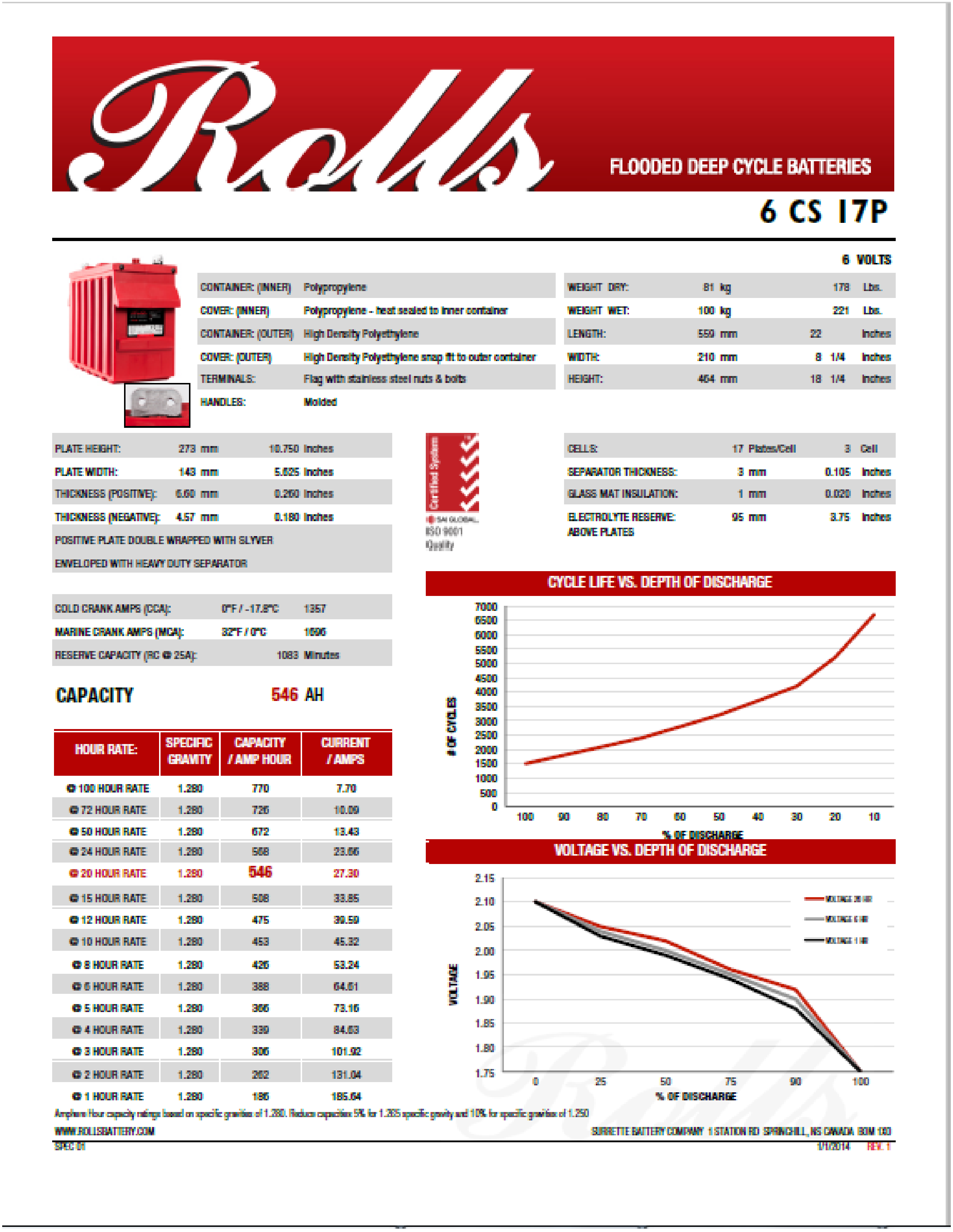
The LG Chem RESU 6.4 EX is a 48V 6.4 kWh lithium-ion battery with a peak power of 5kW that's compatible with SMA Sunny Island 3.0 & 4.4 making it a perfect partner for the SMA Flexible Storage System.

- Compact size (406x664x165 mm) and lightweight (60kg)
- Elegant appearance for flexible siting
- Easy to handle
- Built in circuit breaker
- Simple installation process - takes 5 minutes!
- Up to two 3.2kWh expansion modules can be simply added in order to increase the storage capacity up to a maximum of 12.8kW (Pictured shown)
- Expected lifetime in excess of 10 years of >6000 cycles to 90% DOD

Product Code	Description	Retail Price (ex VAT)
LG-RESU6-4EX	LG Chem Li-Ion 6.4kWh 48V battery pack	£3,320.93
LG-RESU3-2EX	LG Chem Li-Ion 3.2kWh 48V battery expansion pack	£1,927.23

APPENDIX 14 SPECIFICATION FOR LEAD ACID BATTERY

Available at http://www.dcbattery.com/rollssurrette_6cs17p.pdf



FLOODED DEEP CYCLE BATTERIES

6 CS 17P

6 VOLTS

CONTAINER: (INNER)	Polypropylene
COVER: (INNER)	Polypropylene - heat sealed to inner container
CONTAINER: (OUTER)	High Density Polyethylene
COVER: (OUTER)	High Density Polyethylene snap fit to outer container
TERMINALS:	Flag with stainless steel nuts & bolts
HANDLES:	Molded

WEIGHT DRY:	81	kg	178		Lbs.
WEIGHT WET:	100	kg	221		Lbs.
LENGTH:	559	mm	22		Inches
WIDTH:	210	mm	8	1/4	Inches
HEIGHT:	464	mm	18	1/4	Inches

PLATE HEIGHT:	273	mm	10.750	Inches
PLATE WIDTH:	143	mm	5.625	Inches
THICKNESS (POSITIVE):	6.60	mm	0.260	Inches
THICKNESS (NEGATIVE):	4.57	mm	0.180	Inches

POSITIVE PLATE DOUBLE WRAPPED WITH SLYVER

ENVELOPED WITH HEAVY DUTY SEPARATOR

Certified System
SAI GLOBAL
ISO 9001
Quality

CELLS:	17	Plates/Cell	3	Cell
SEPARATOR THICKNESS:	3	mm	0.105	Inches
GLASS MAT INSULATION:	1	mm	0.020	Inches
ELECTROLYTE RESERVE: ABOVE PLATES	95	mm	3.75	Inches

COLD CRANK AMPS (CCA):	0°F / -17.8°C	1357	
MARINE CRANK AMPS (MCA):	32°F / 0°C	1696	
RESERVE CAPACITY (RC @ 25A):		1083	Minutes

CAPACITY 546 AH

HOUR RATE:	SPECIFIC GRAVITY	CAPACITY / AMP HOUR	CURRENT / AMPS
@ 100 HOUR RATE	1.280	770	7.70
@ 72 HOUR RATE	1.280	726	10.09
@ 50 HOUR RATE	1.280	672	13.43
@ 24 HOUR RATE	1.280	568	23.66
@ 20 HOUR RATE	1.280	546	27.30
@ 15 HOUR RATE	1.280	508	33.85
@ 12 HOUR RATE	1.280	475	39.59
@ 10 HOUR RATE	1.280	453	45.32
@ 8 HOUR RATE	1.280	426	53.24
@ 6 HOUR RATE	1.280	388	64.61
@ 5 HOUR RATE	1.280	366	73.16
@ 4 HOUR RATE	1.280	339	84.63
@ 3 HOUR RATE	1.280	306	101.92
@ 2 HOUR RATE	1.280	262	131.04
@ 1 HOUR RATE	1.280	186	185.64

Ampere Hour capacity ratings based on specific gravities of 1.280. Reduce capacities 5% for 1.265 specific gravity and 10% for specific gravities of 1.250

CYCLE LIFE VS. DEPTH OF DISCHARGE

VOLTAGE VS. DEPTH OF DISCHARGE

WWW.ROLLSBATTERY.COM

SURRETTE BATTERY COMPANY 1 STATION RD SPRINGHILL, NS CANADA B0M 1X0

SPEC 01

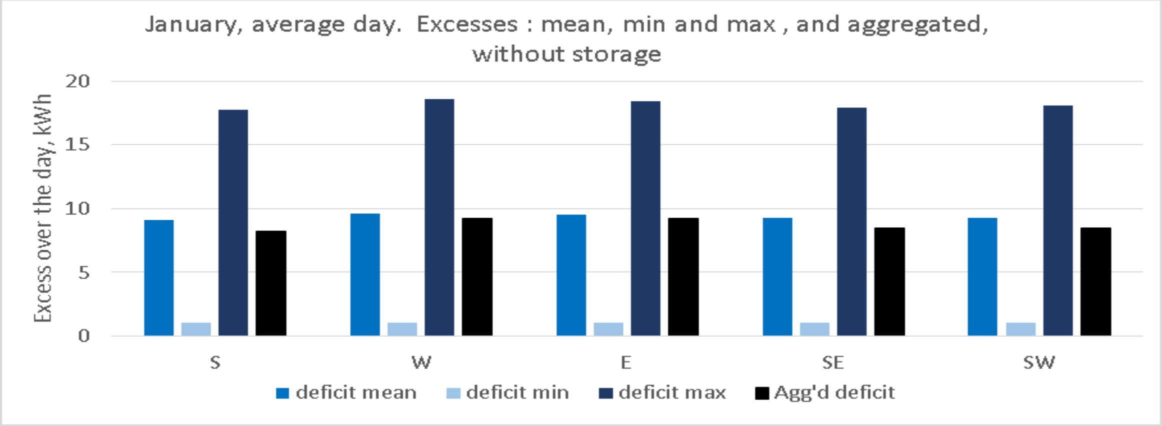
1/1/2014 REV. 1

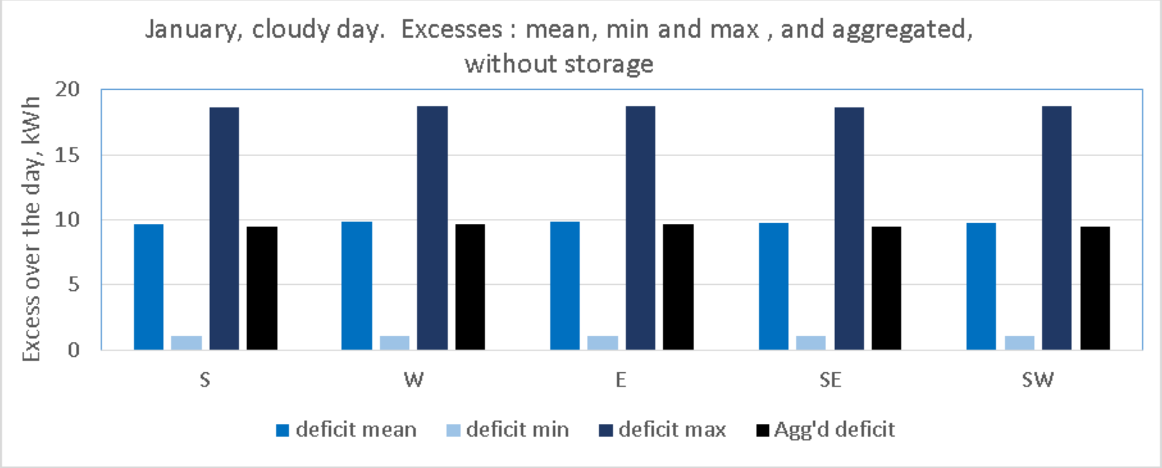
APPENDIX 15 EXCESSES AND DEFICITS IN GENERATION - URBAN SCENARIOS. THE EFFECT OF ORIENTATION

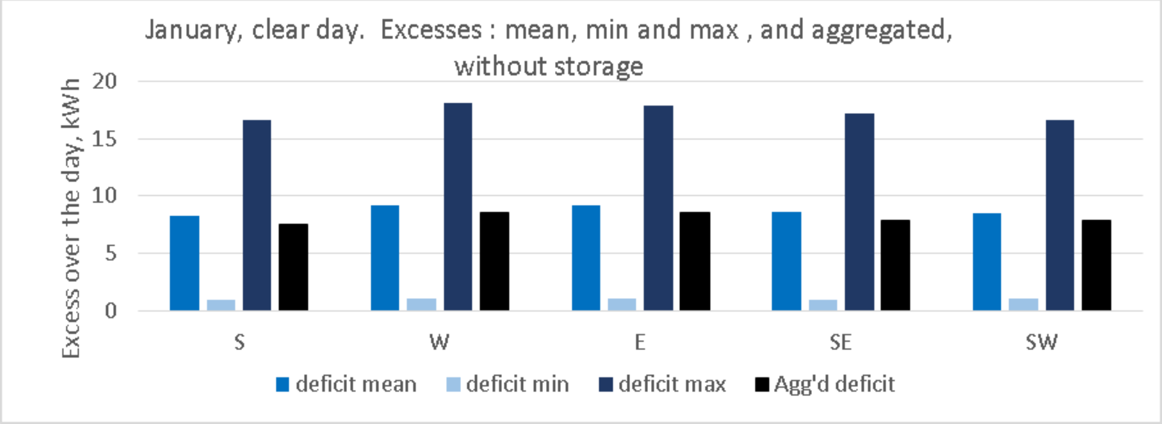
The charts below show day total excesses and deficits in generation, for five orientations, of 100 runs, “Ballindalloch” scenario. In all cases, there is no storage.

Deficits, winter, with no storage

Across the 100 runs, there is a range of day total deficits in generation. Here, for each orientation, the *mean* day total deficit (mid-blue), the *minimum* deficit (pale), and the *maximum* deficit (dark blue) of the 100 individual runs are displayed together. The day total deficit *for an aggregation of the same 100 runs* is also shown, in black. These deficits, for an “average” day, a “cloudy” day and a “clear” day are shown in three separate graphs below.

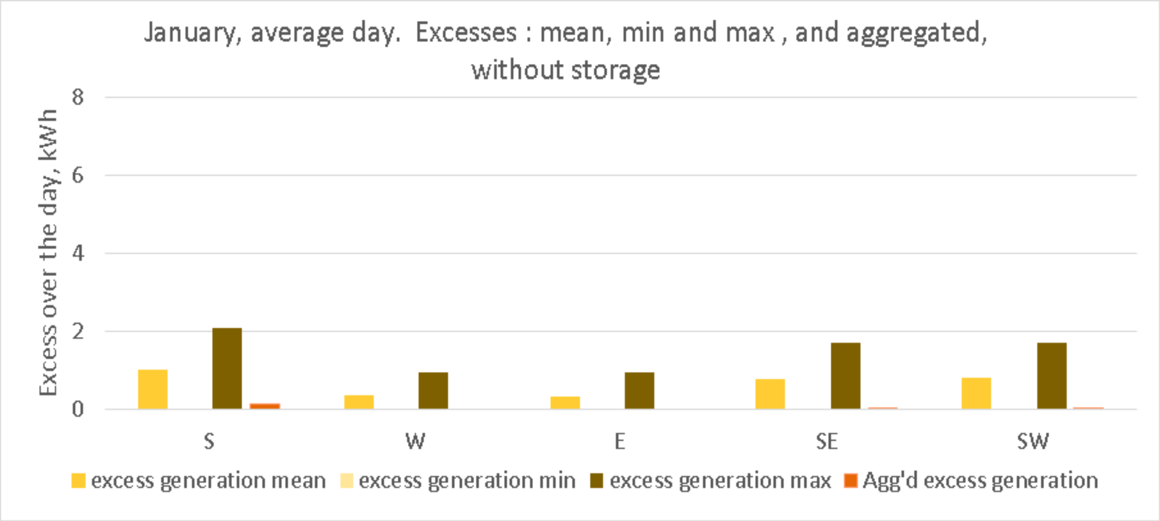


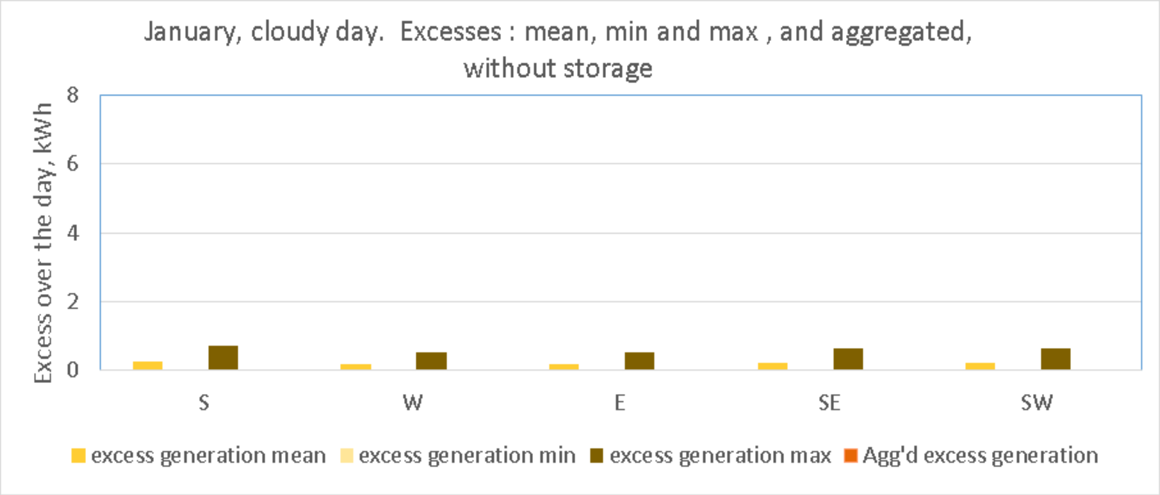


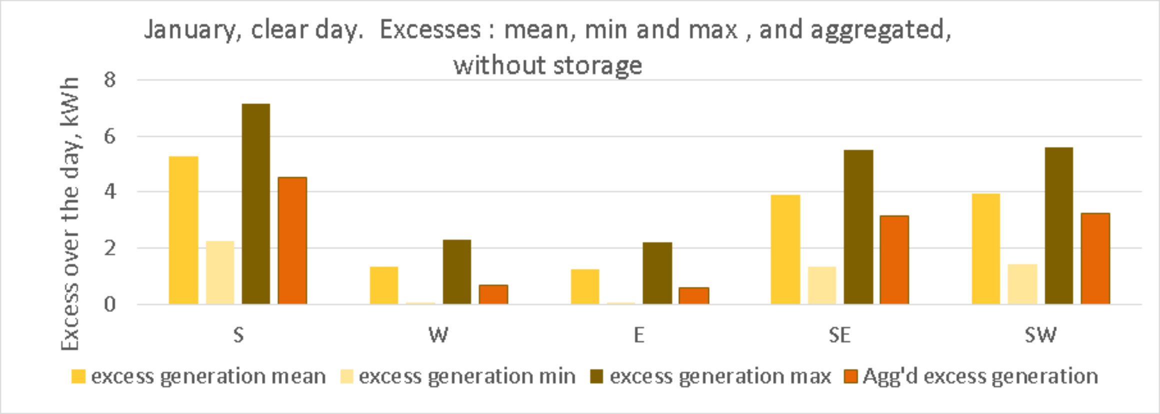


Excesses, winter, with no storage

Similarly, across the 100 runs, there is a range of day total excesses. Here, for each orientation, the *mean* day total excess (yellow), the *minimum* excess (pale), and the *maximum* excess (brown) of the 100 individual runs, are displayed together. The day total excess *for an aggregation of the same 100 runs* is also shown, in orange. The excesses for an "average" day, a "cloudy" day and a "clear" day are shown in three separate graphs below.

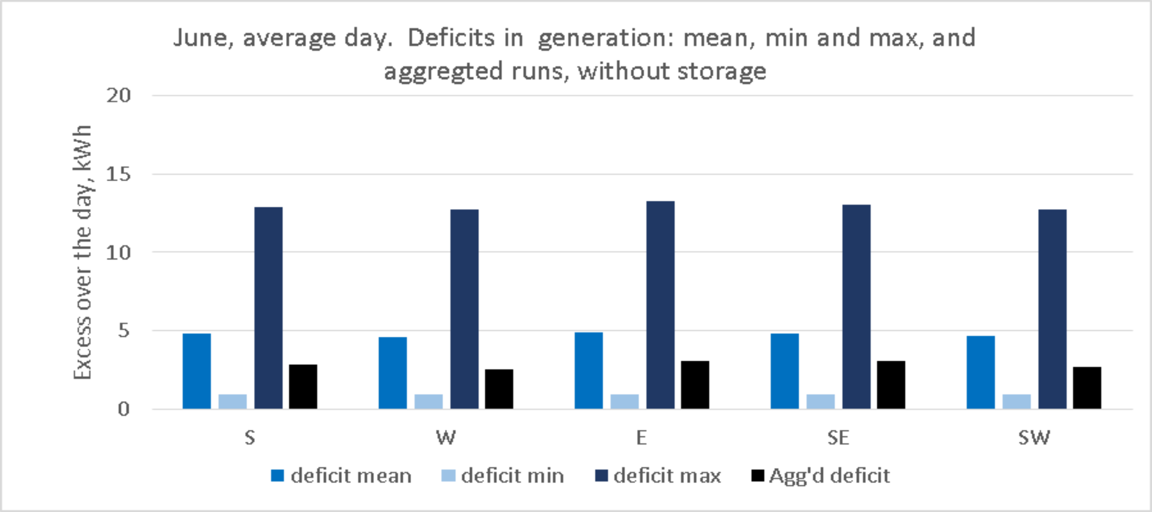


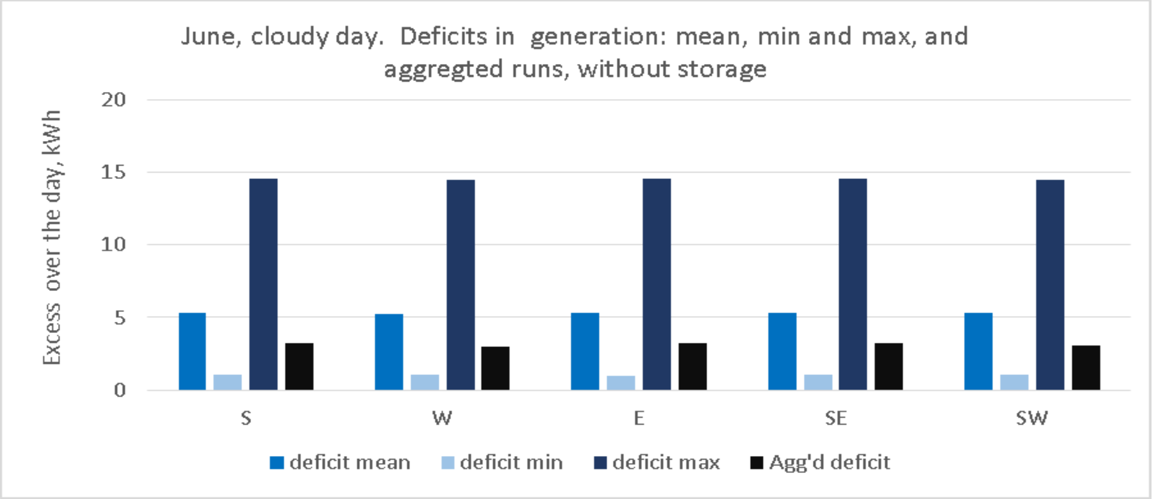


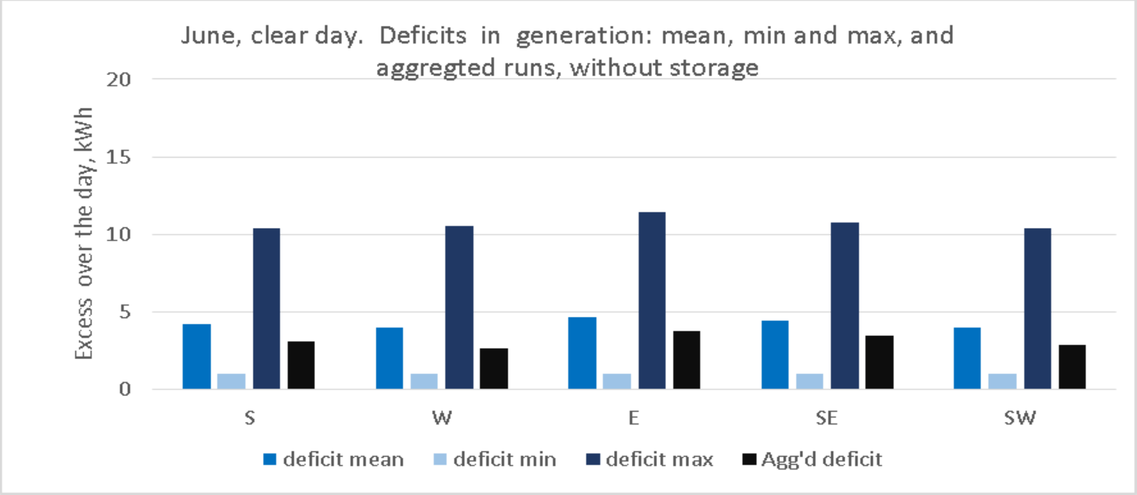


Deficits, summer, no storage

As above, the mean, minimum, and maximum of the day total deficits in generation, across the 100 runs, are displayed together, for each orientation. The last in the group, in black, is the day total deficit of an aggregation of the same 100 runs. Total deficits on an "average" day, a "cloudy" day and a "clear" day are shown in three separate graphs below.

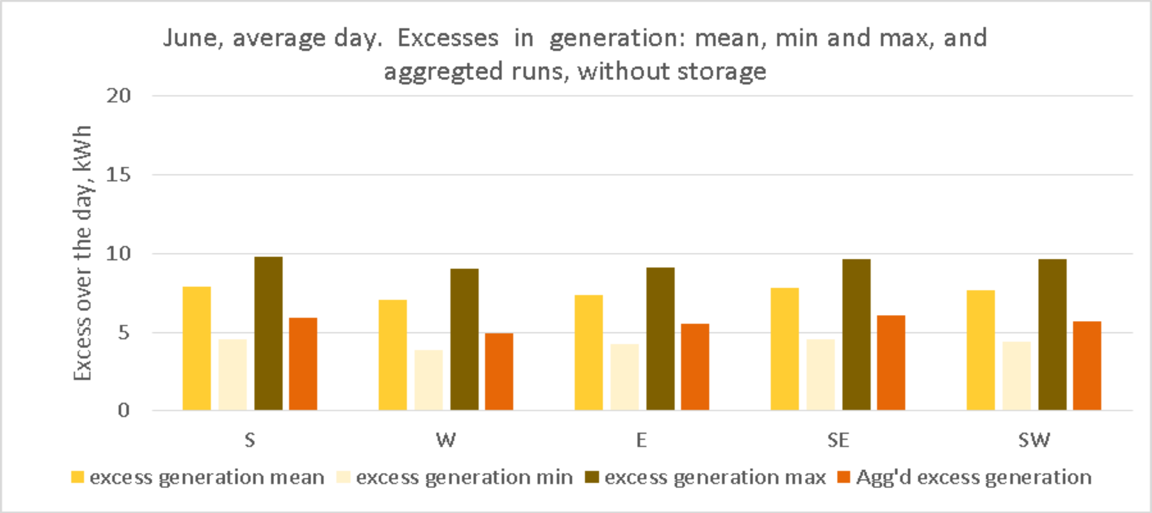


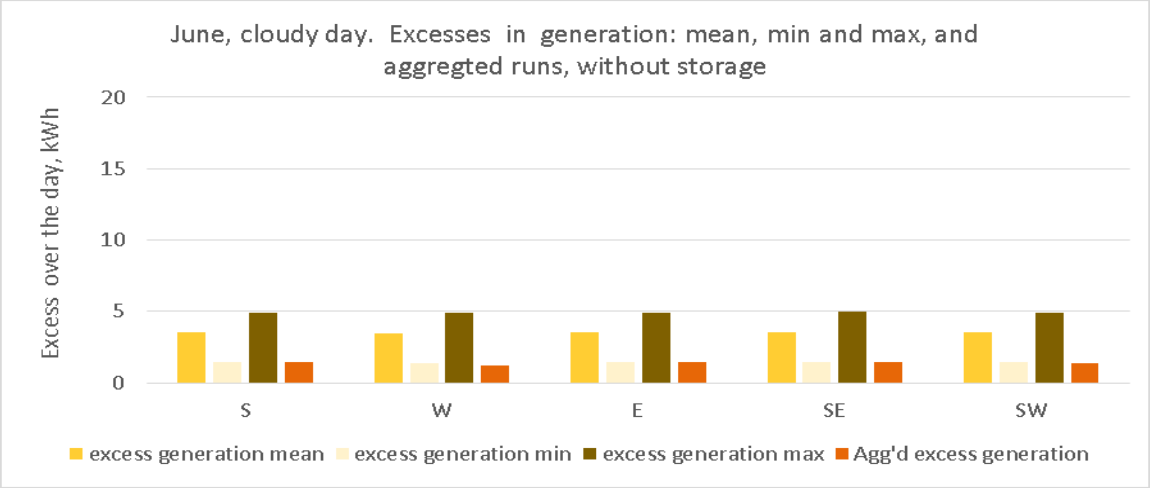


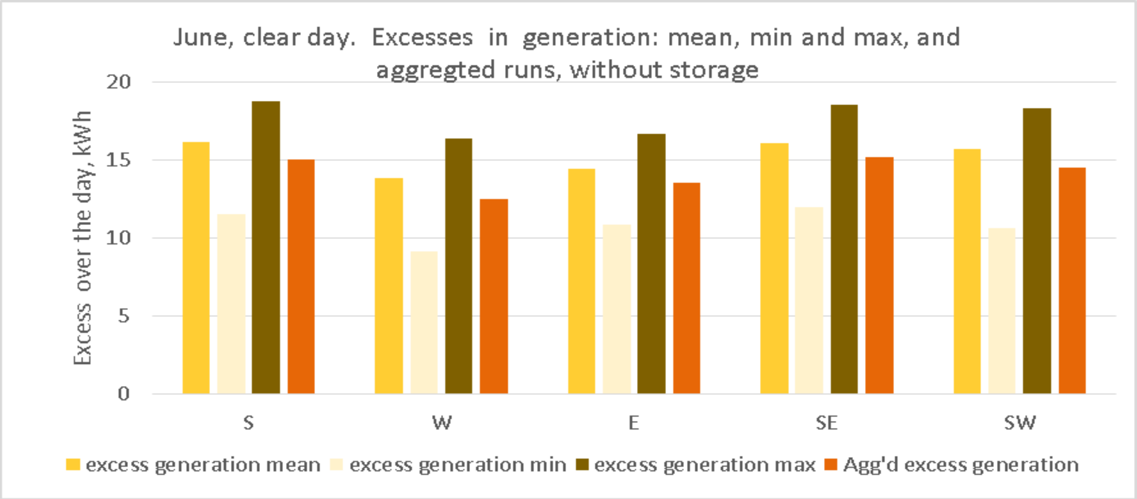


Excesses, summer, with no storage

As above, the mean, minimum, and maximum of the day total excesses in generation, across the 100 runs, are displayed together, for each orientation. The last in the group, in orange, is the day total excess of an aggregation of the same 100 runs. Total excesses, on an “average” day, a “cloudy” day and a “clear” day are shown in three separate graphs below.





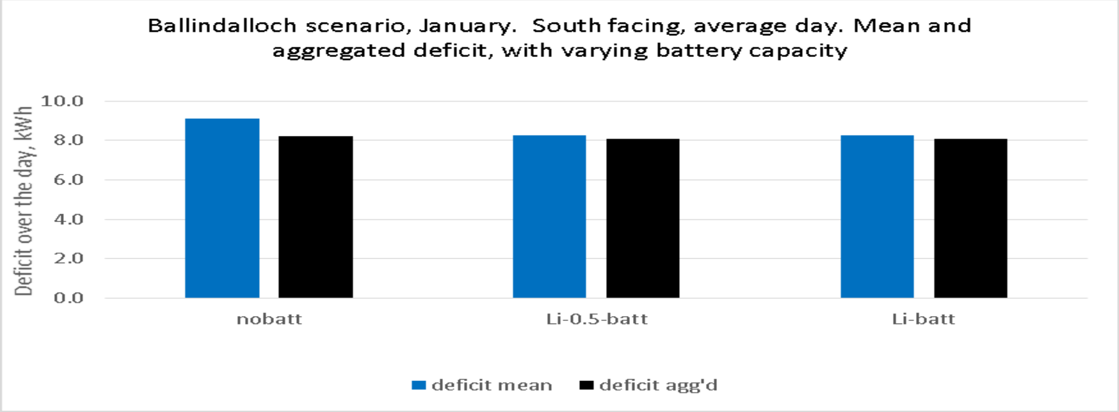


APPENDIX 16 THE EFFECT OF ADDING STORAGE, ON DAY TOTAL DEFICITS IN GENERATION. URBAN SCENARIO

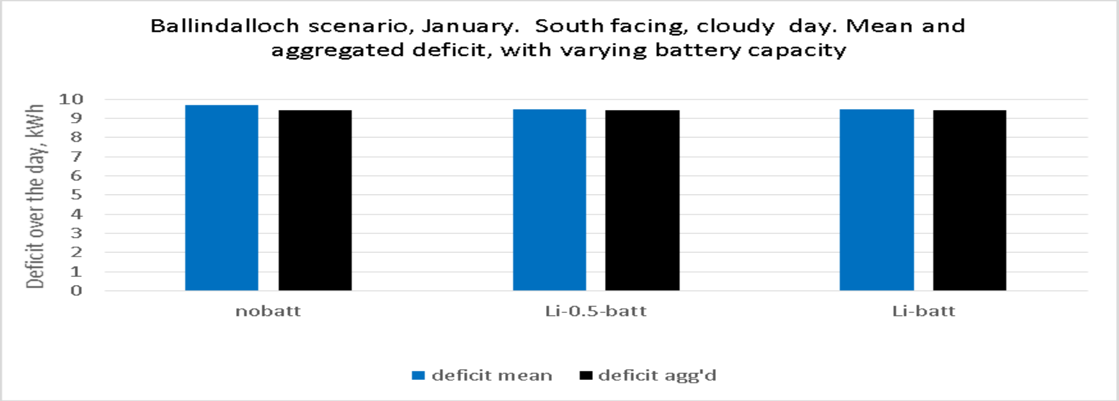
100 runs of the “Ballindalloch” scenario were examined. The *mean* of the day total deficits of the 100 runs are displayed below (blue bar), and the day total deficit *of an aggregation of the same 100 runs* is shown (black bar). Each graph shows the effect of adding increasing quantities of storage capacity. The deficits for average weather day, a cloudy day, and a clear day, are shown separately.

Winter

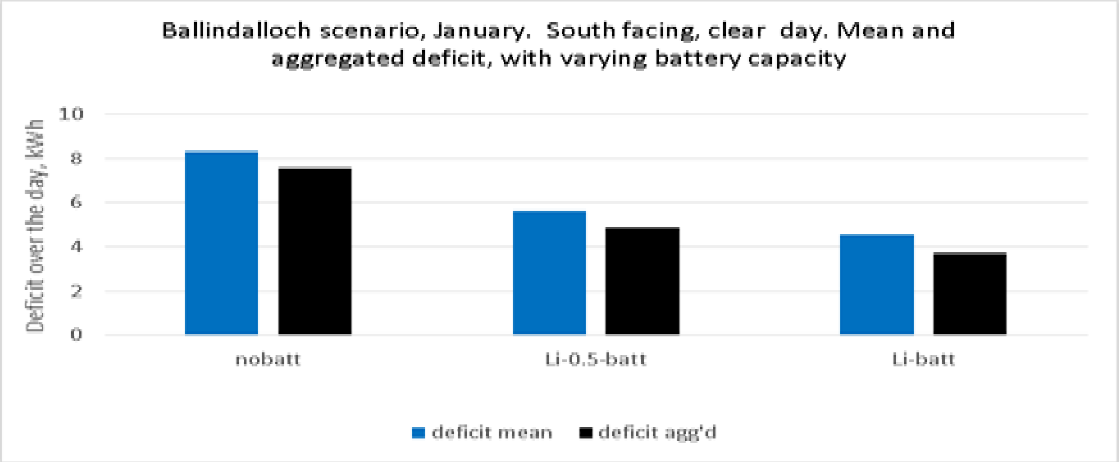
Deficits, winter, “average weather” conditions



Deficits in generation on a cloudy winter day



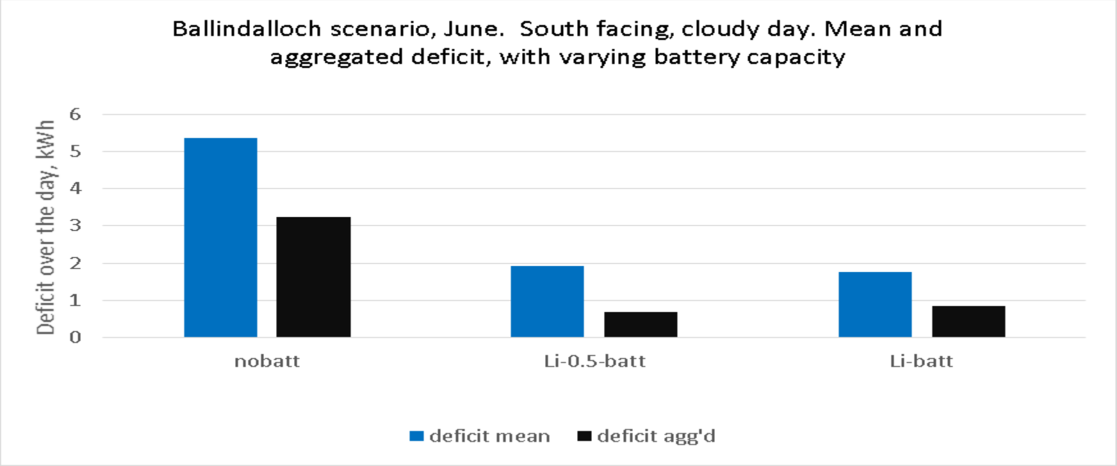
Deficits in generation on a clear winter day



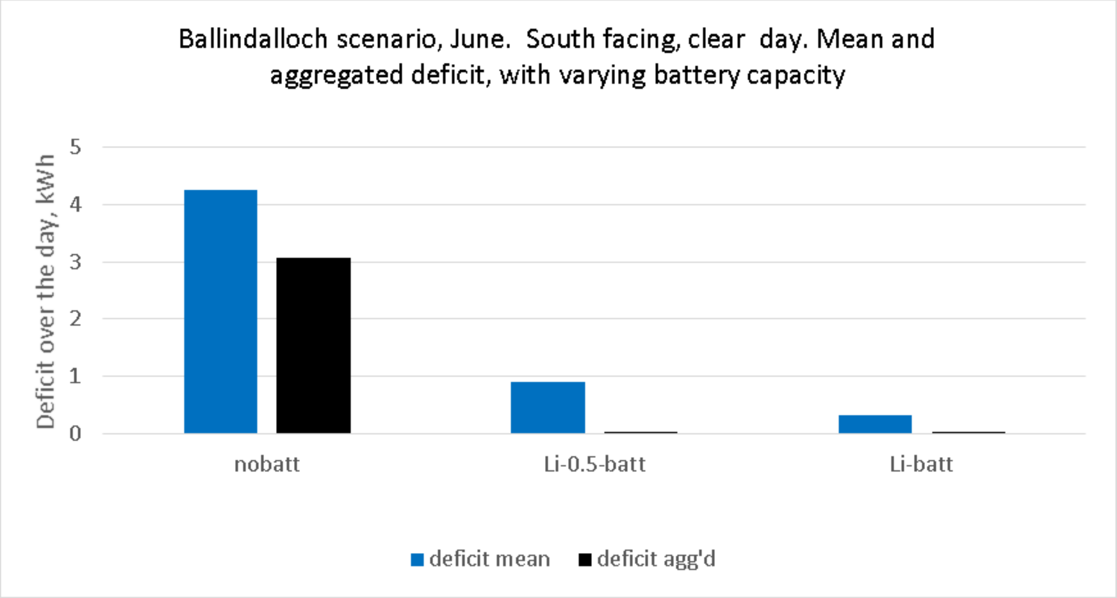
For all the winter graphs, a minimum initial state of charge of the battery was used. This is representative of runs on average and cloudy days, and is very close to the initial state of charge following a clear day.

Summer

Deficits in generation on a cloudy summer day



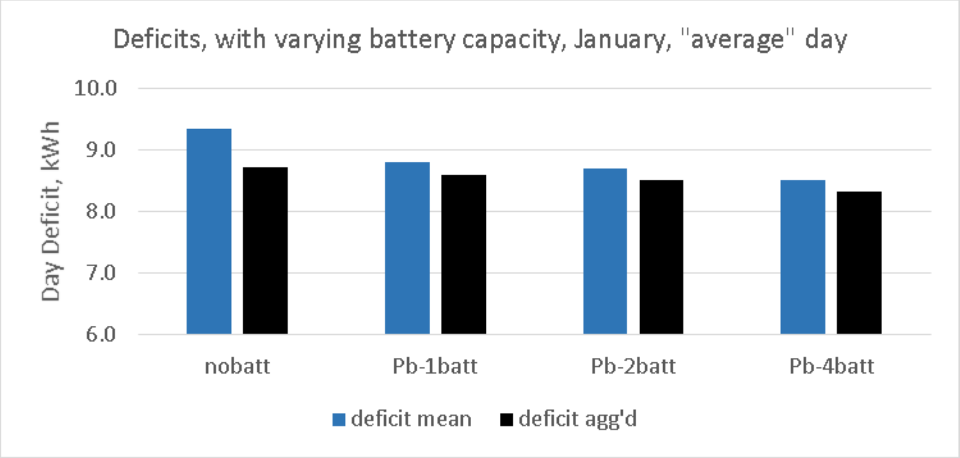
Deficits in generation on a clear summer day

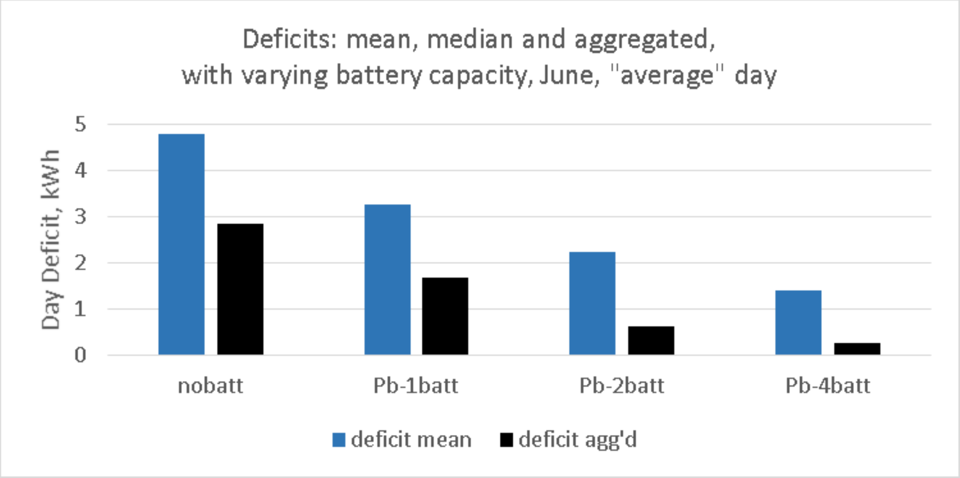


In both the above cases, an initial State of charge of battery, typical of an “average weather” preceding day, was used.

APPENDIX 17 EFFECT OF LEAD-ACID BATTERY STORAGE ON DEFICITS: URBAN BALLINDALLOCH SCENARIO

(All assumed an initial SOC of 0.25. This will cause a small error in some runs, as in winter the SOC will be lower, and after clear or average days in summer, the SOC will be higher.

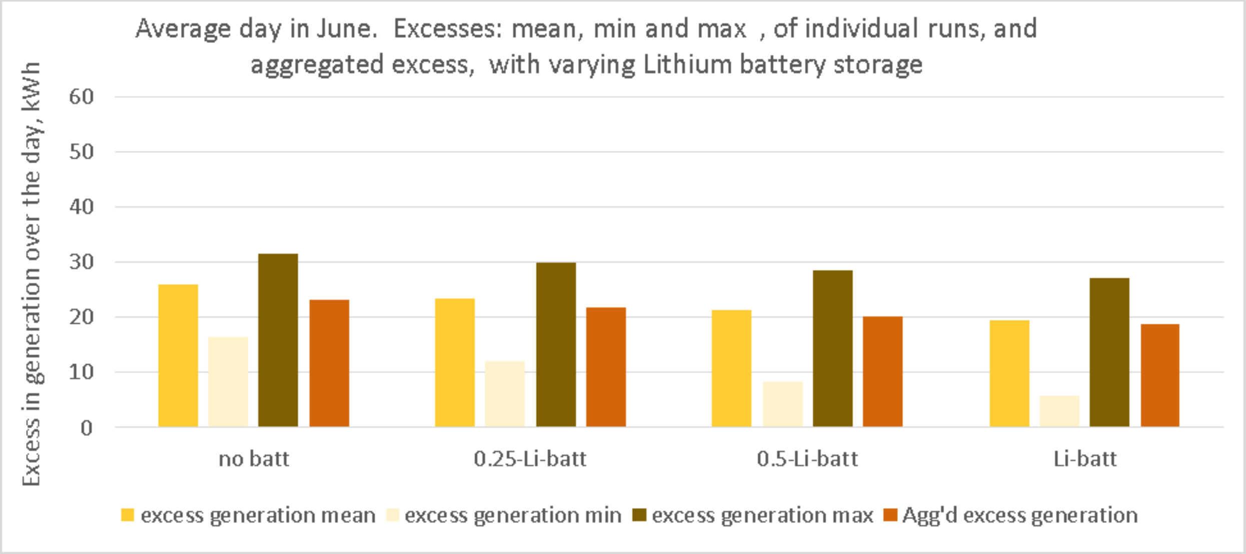


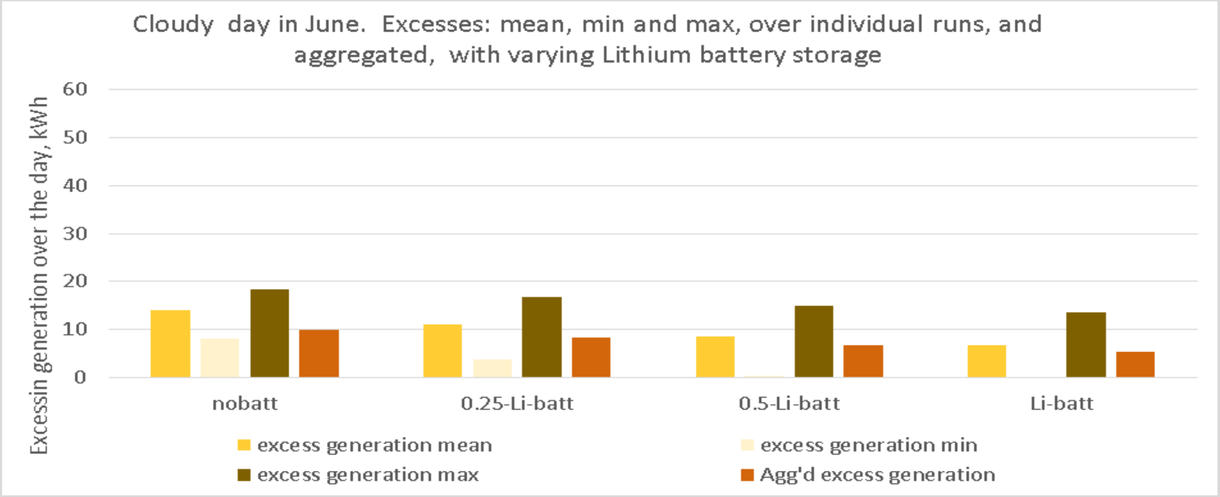


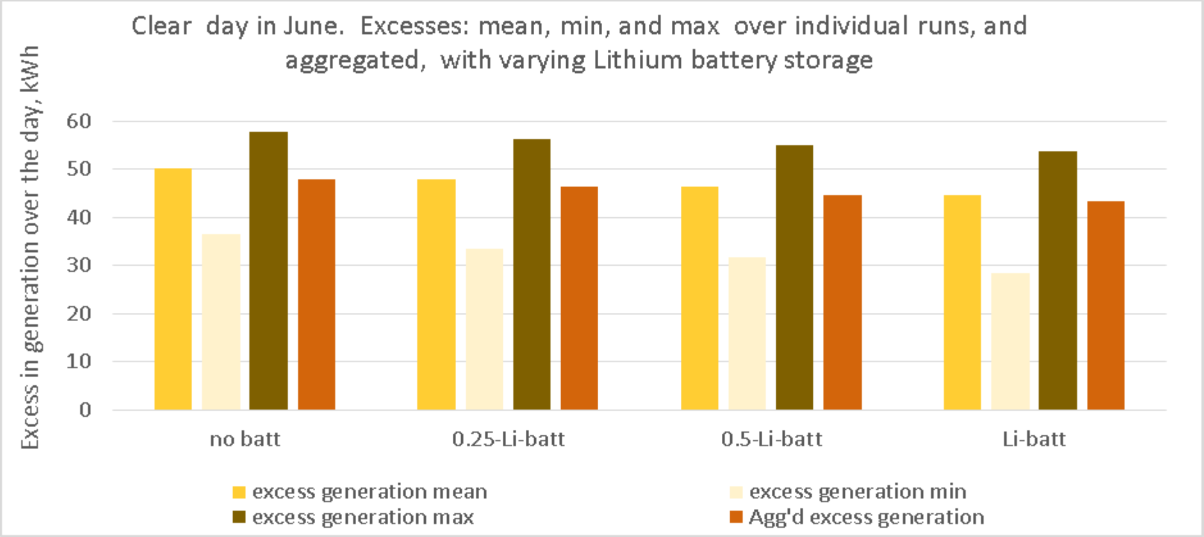
APPENDIX 18 EXCESSES AND DEFICITS IN GENERATION - RURAL SCENARIOS

Summer

Day total excesses in generation, with lithium battery storage, are depicted below.



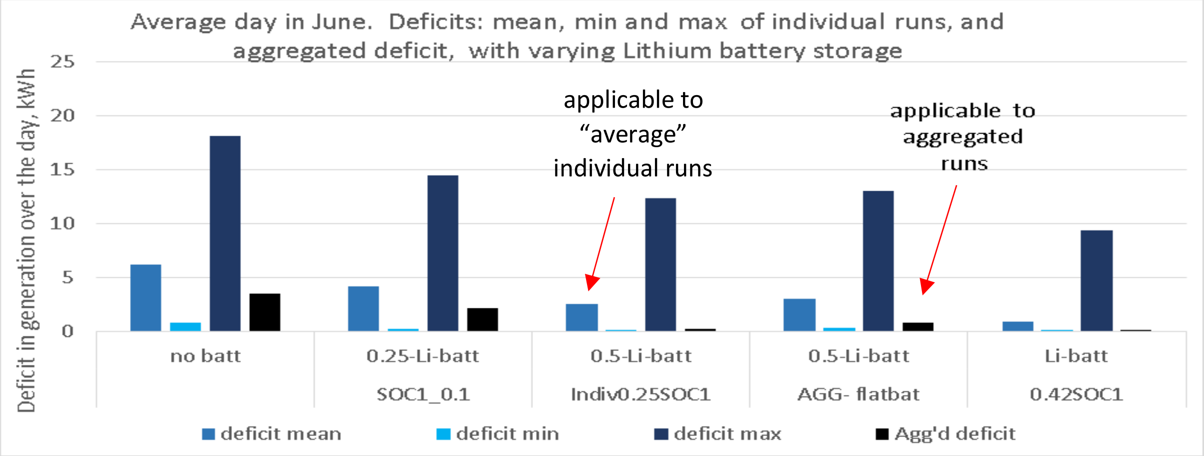


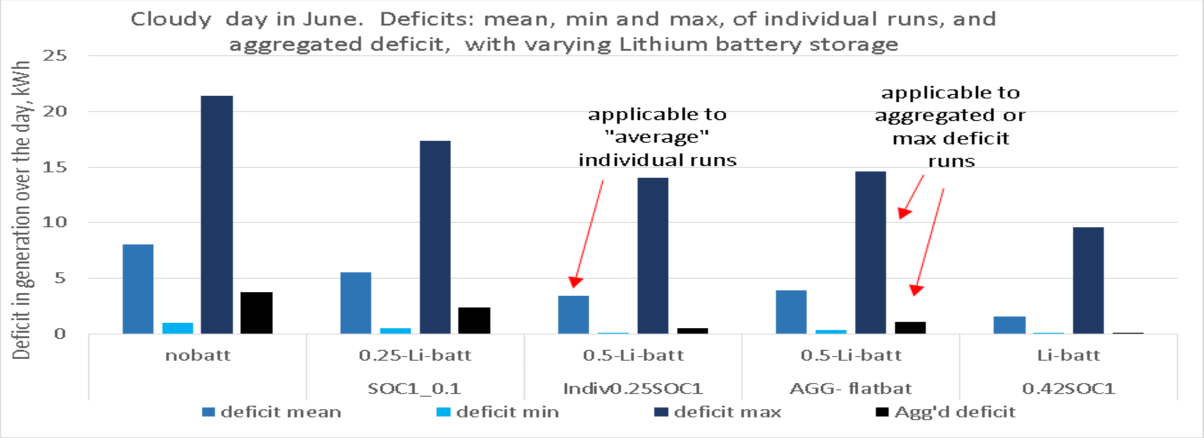


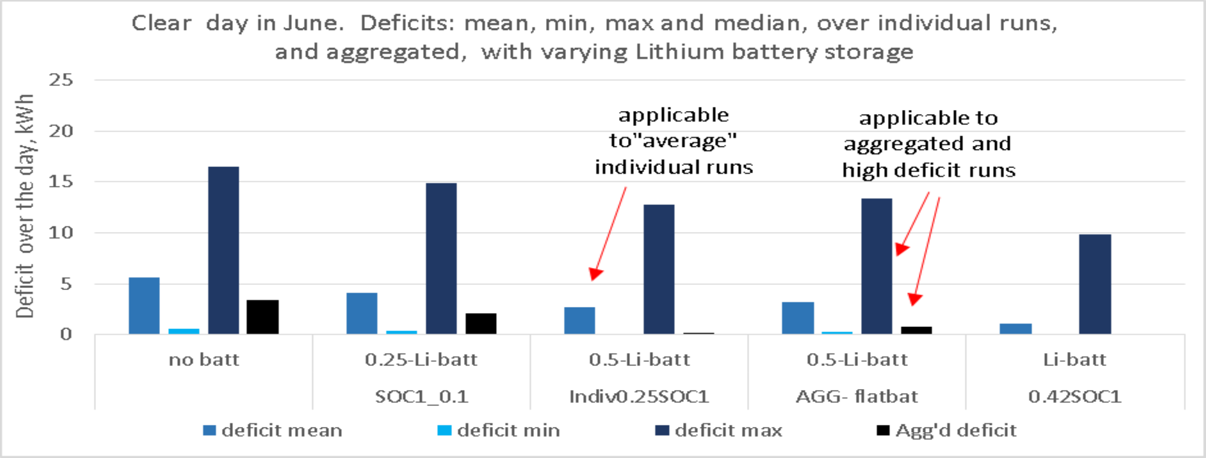
Day total deficits with varying lithium battery storage, are displayed below

Key:

Legend	
0.25Li-batt, SOC1_0.1	One quarter standard lithium battery, initial state of charge (SOC) 0.1
0.5Li-Batt, Indiv0.25SOC1	One half standard lithium battery, initial SOC 0.25, representative of mean / median individual runs
0.5-Li-batt, AGG-flatbat	One half standard lithium battery, initial SOC the minimum charge, representative of aggregated runs
Li-batt 0.42SOC1	One standard lithium battery, initial SOC 0.42. Broadly representative of both mean//median individual and aggregated runs.



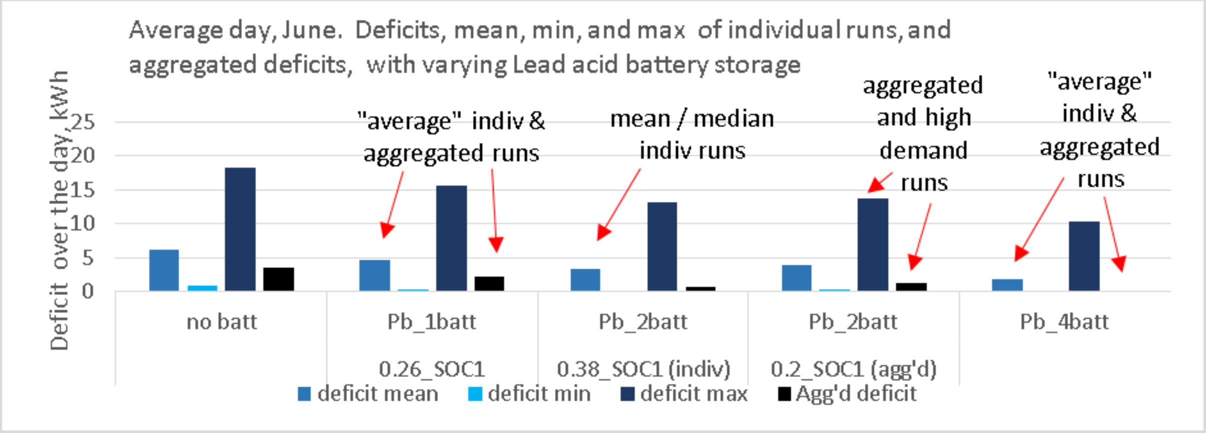


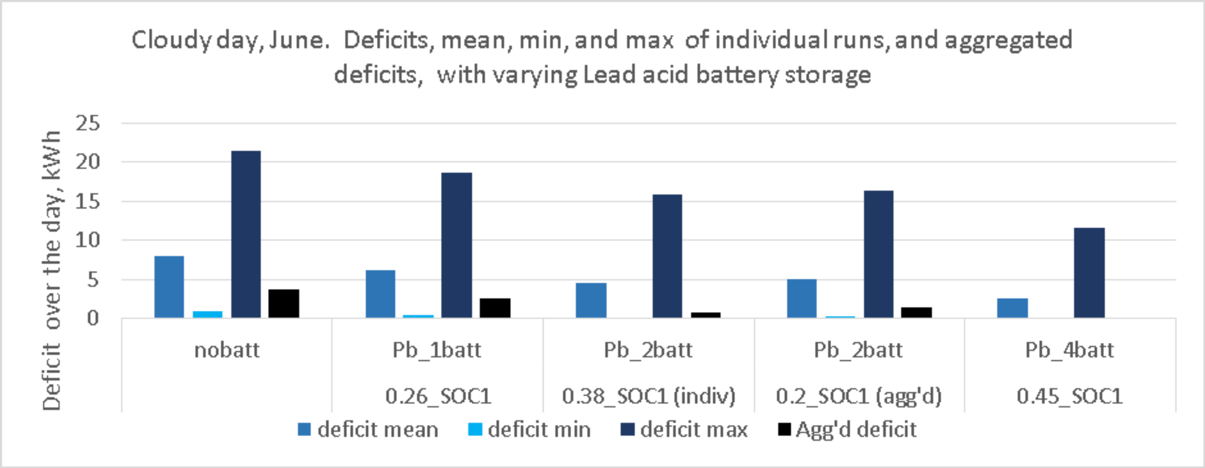


Day total deficits in generation, with varying lead acid battery storage, are depicted below.

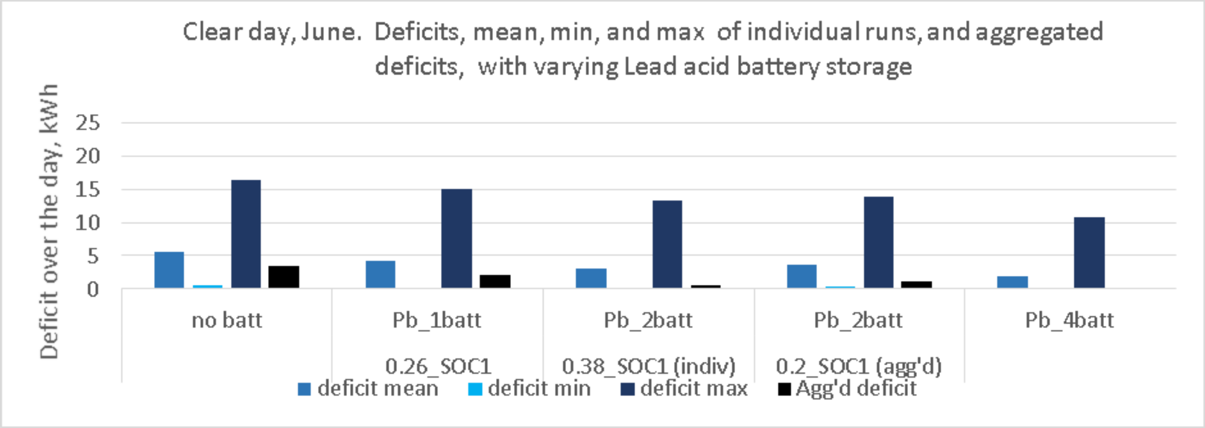
Key:

Legend	
no batt	No storage
Pb_1batt, 0.26_SOC1	One standard lead battery, initial SOC 0.26
Pb_2batt, 0.38 SOC1(indiv)	Two standard lead batteries, initial SOC 0.38, representative of mean / median individual runs
Pb_2batt, 0.2_SOC (agg'd)	Two standard lead batteries, initial SOC 0.2 (the minimum), representative of aggregated runs
Pb_4batt	Four standard lead batteries, initial SOC 0.45, broadly representative of mean / median individual, and aggregated, runs





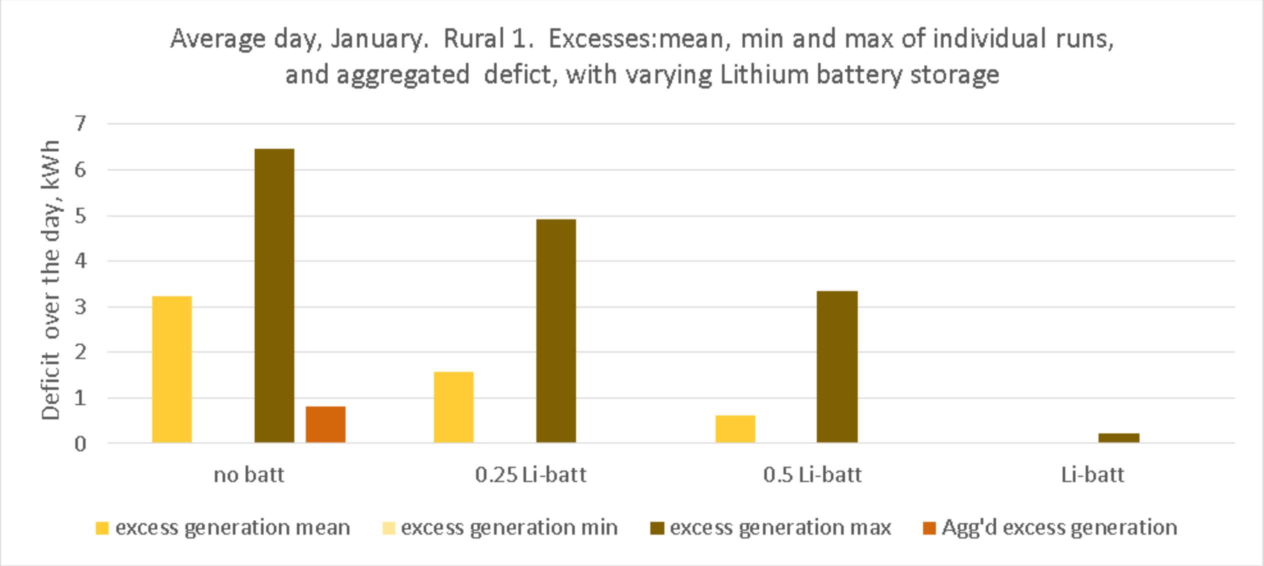
Cloudy day, June. Deficits, mean, min, and max of individual runs, and aggregated deficits, with varying Lead acid battery storage
Deficit over the day, kWh
25
20
15
10
5
0
nobatt
Pb_1batt
0.26_SOC1
Pb_2batt
0.38_SOC1 (indiv)
Pb_2batt
0.2_SOC1 (agg'd)
Pb_4batt
0.45_SOC1
deficit mean
deficit min
deficit max
Agg'd deficit



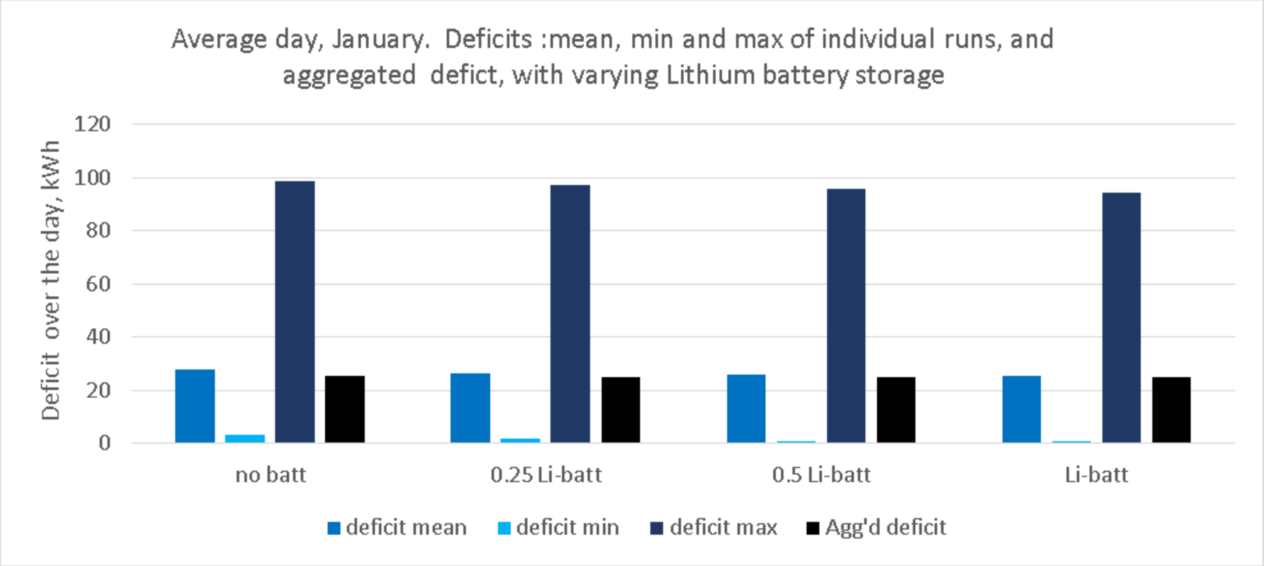
Clear day, June. Deficits, mean, min, and max of individual runs, and aggregated deficits, with varying Lead acid battery storage
Deficit over the day, kWh
25
20
15
10
5
0
no batt
Pb_1batt
0.26_SOC1
Pb_2batt
0.38_SOC1 (indiv)
Pb_2batt
0.2_SOC1 (agg'd)
Pb_4batt
deficit mean
deficit min
deficit max
Agg'd deficit

<u>January, Rural 1 scenario</u> (with significant electrical heating, including storage heating)

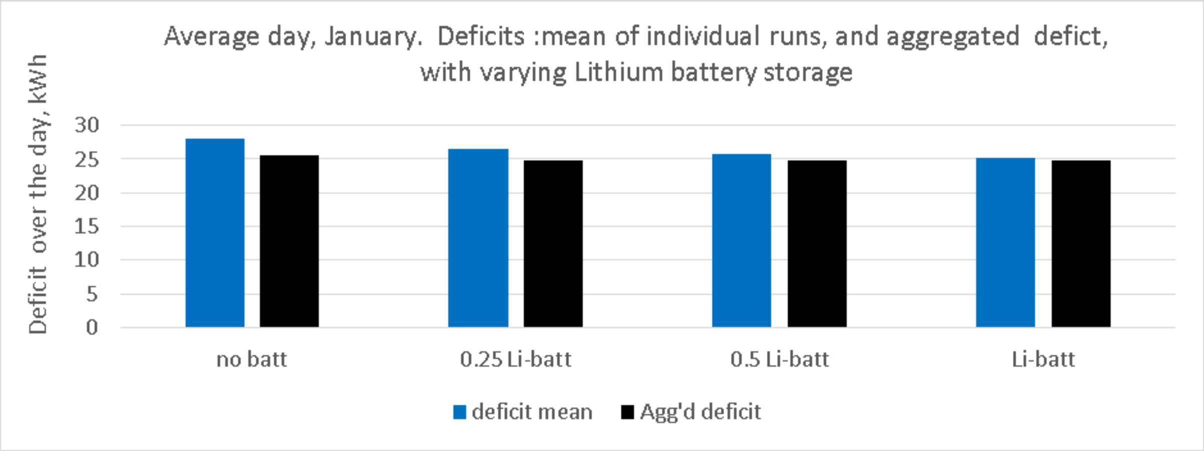
Excesses in generation, with varying lithium battery storage, are shown below.

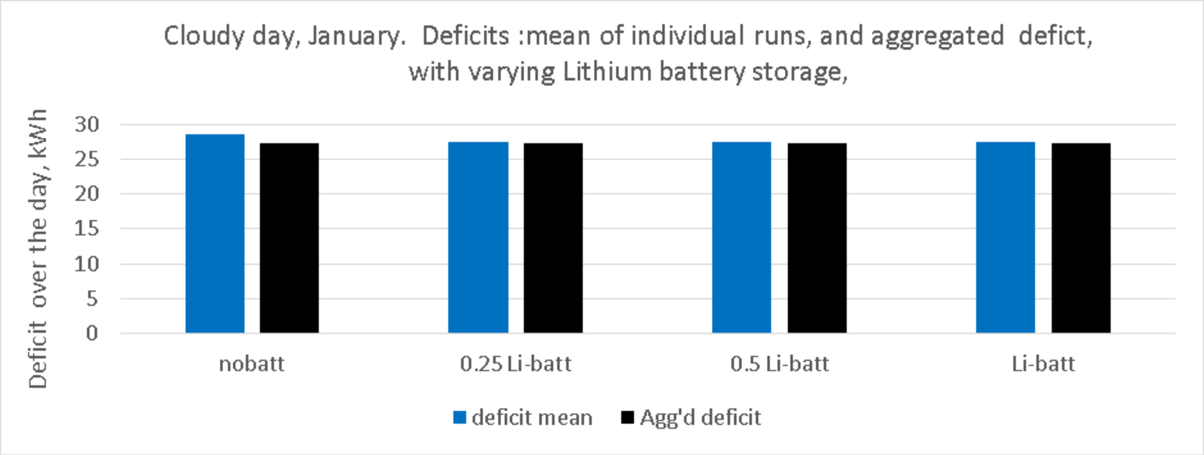


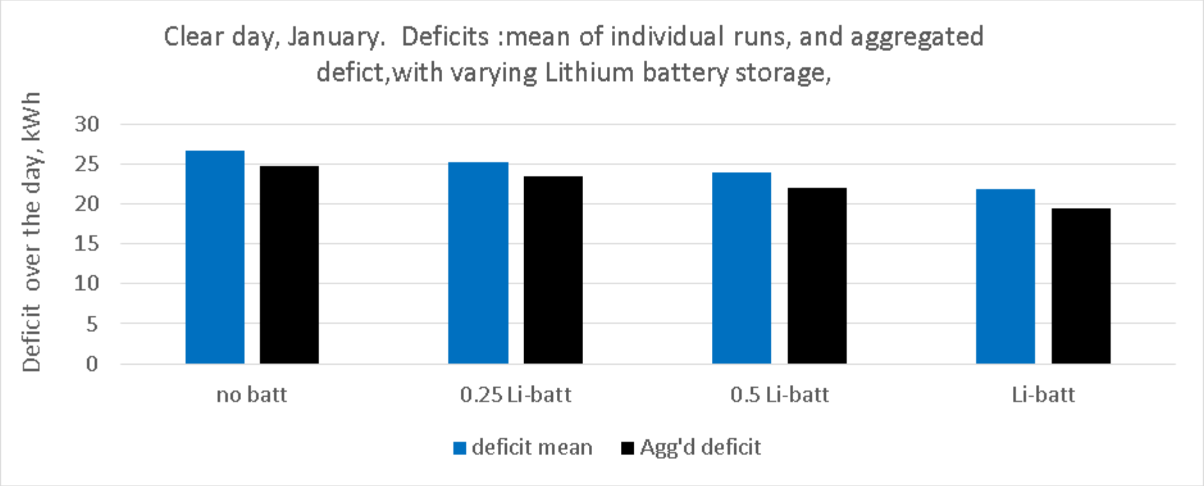
Day total deficits with varying lithium battery storage, are displayed below. All runs are done with minimum charge in the battery at the beginning of each run.



Showing only the mean of individual runs, and deficit of an aggregation of runs, on "average", "cloudy" and "clear" day:-

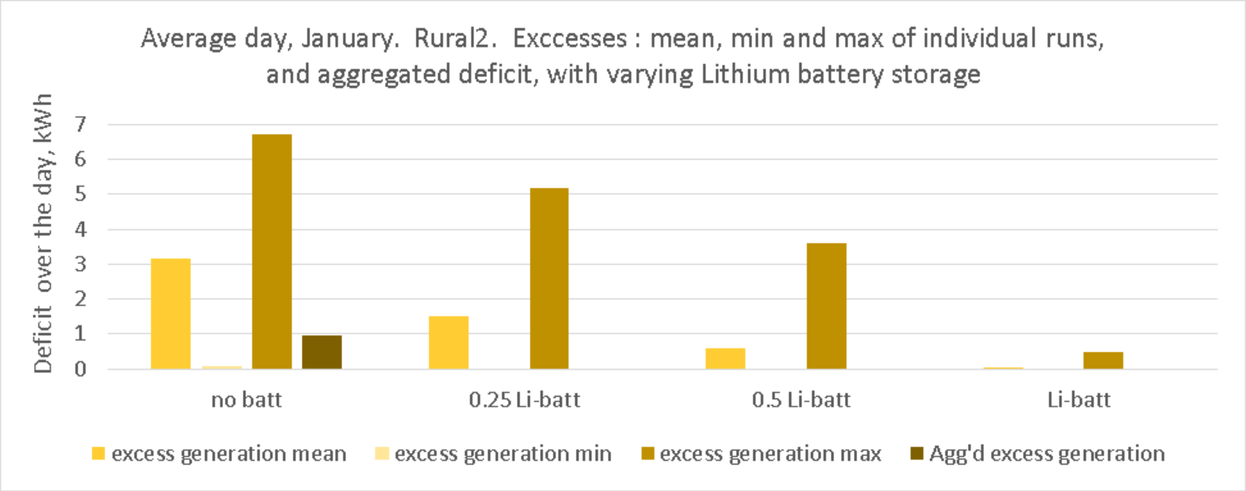




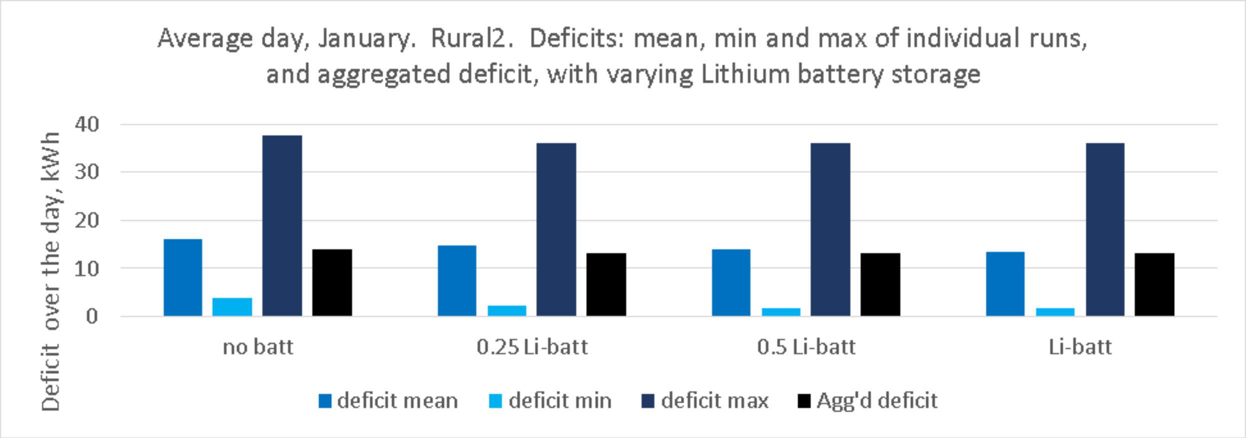


Rural 2 scenario (no storage heating)

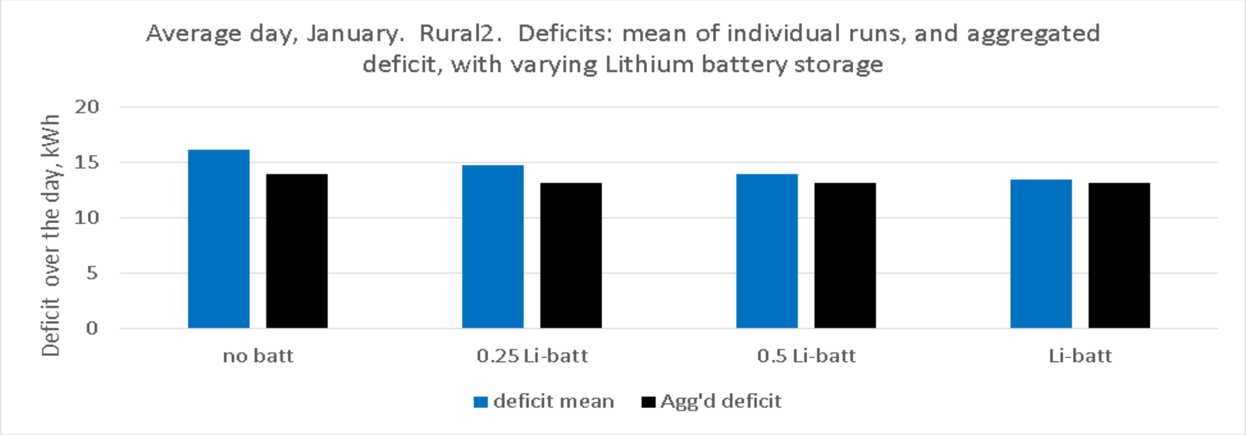
Excesses are shown below.

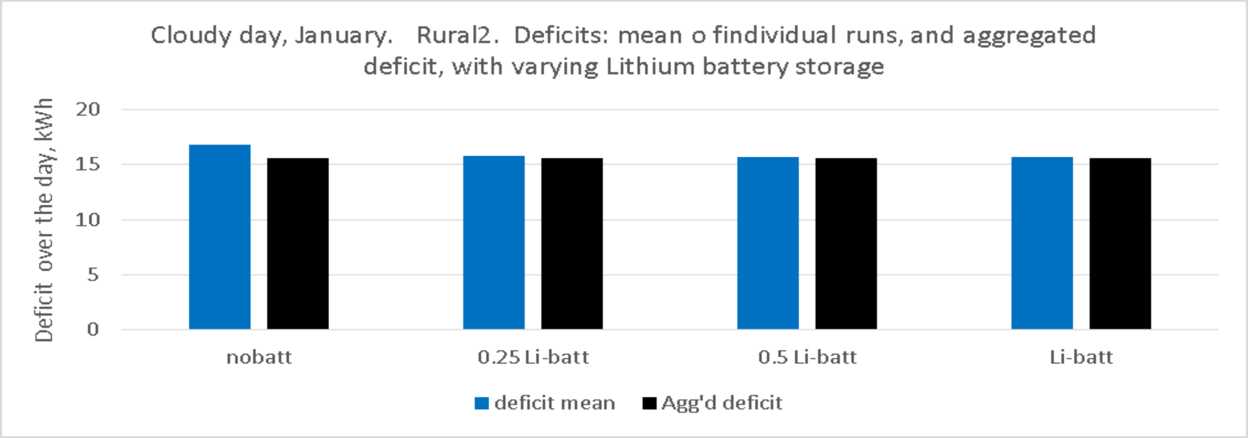


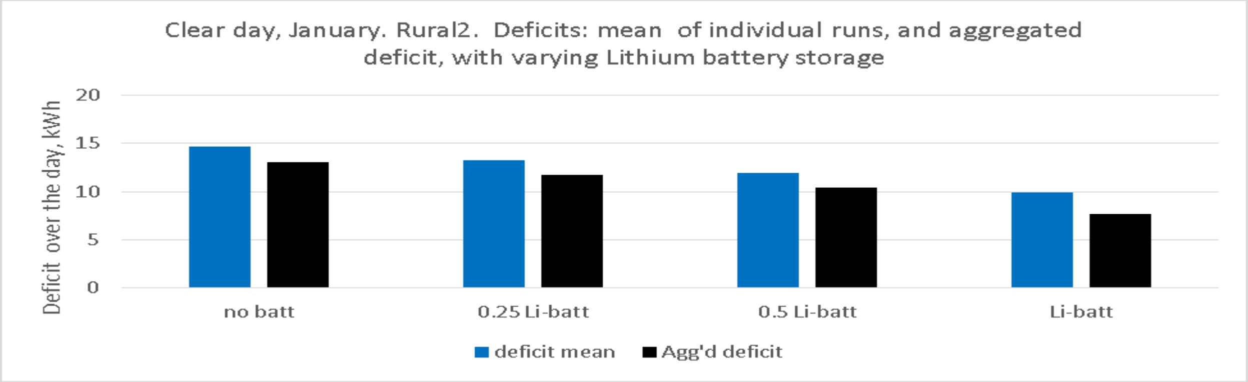
Deficits are shown below.



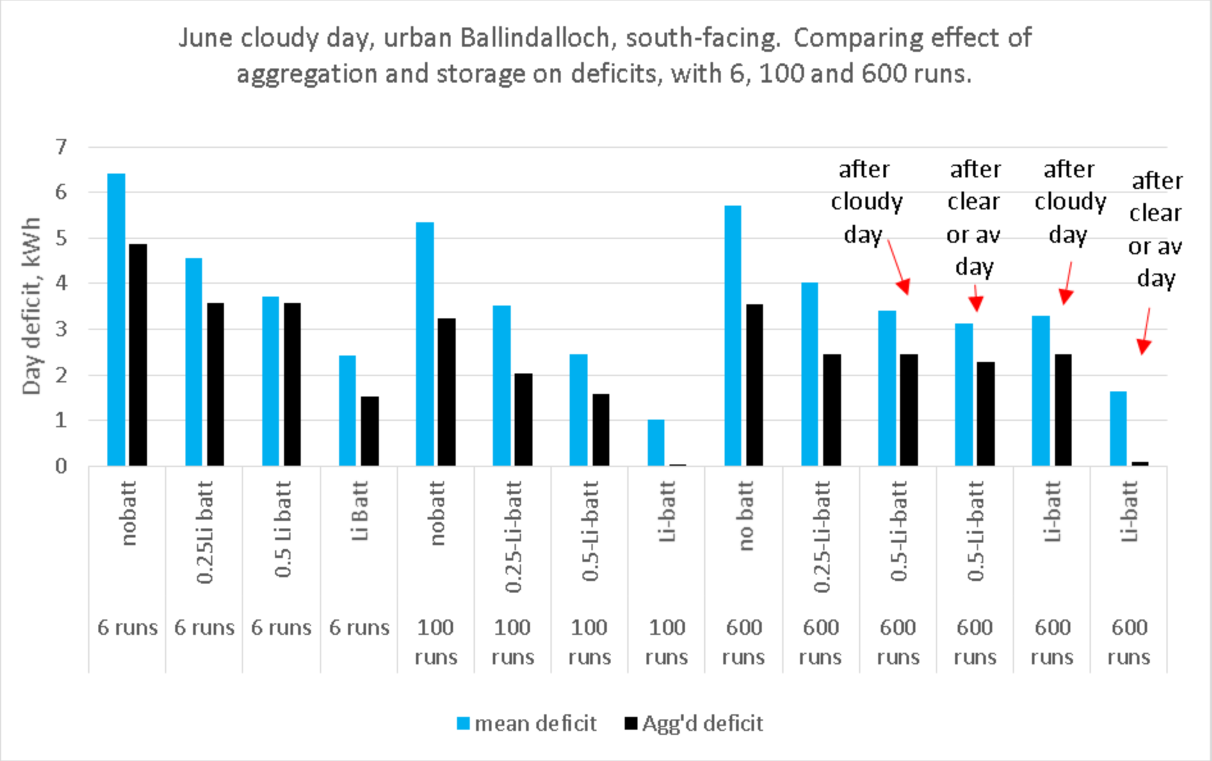
Showing only the mean of individual runs, and the deficit of an aggregation of runs:-

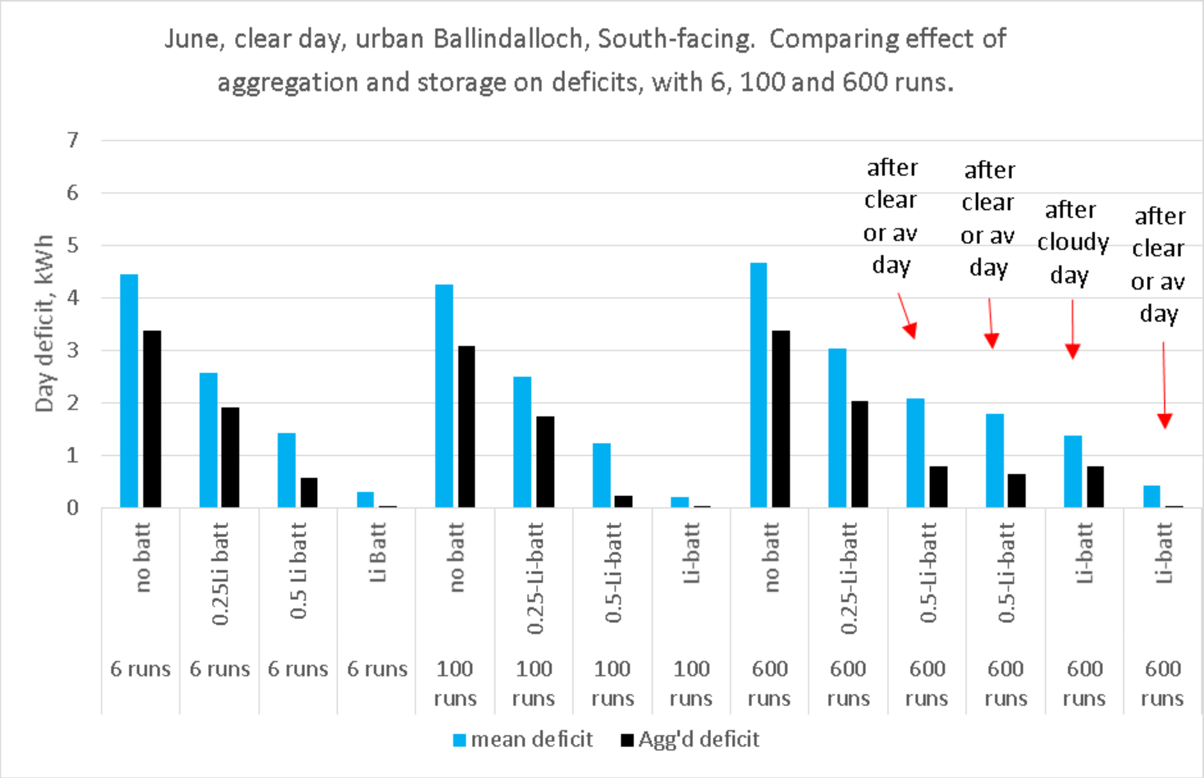


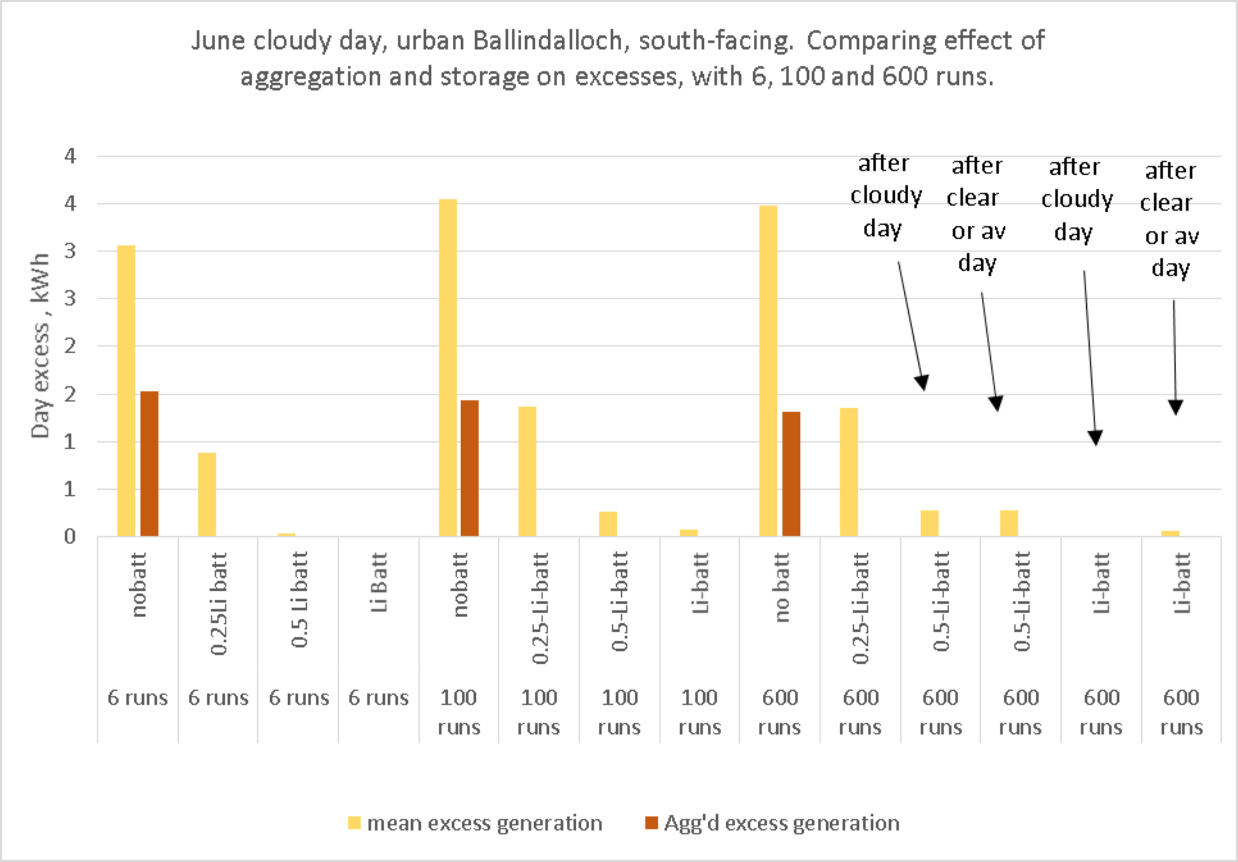

Cloudy day, January. Rural2. Deficits: mean o findividual runs, and aggregated deficit, with varying Lithium battery storage
Deficit over the day, kWh
20
15
10
5
0
nobatt
0.25 Li-batt
0.5 Li-batt
Li-batt
deficit mean
Agg'd deficit

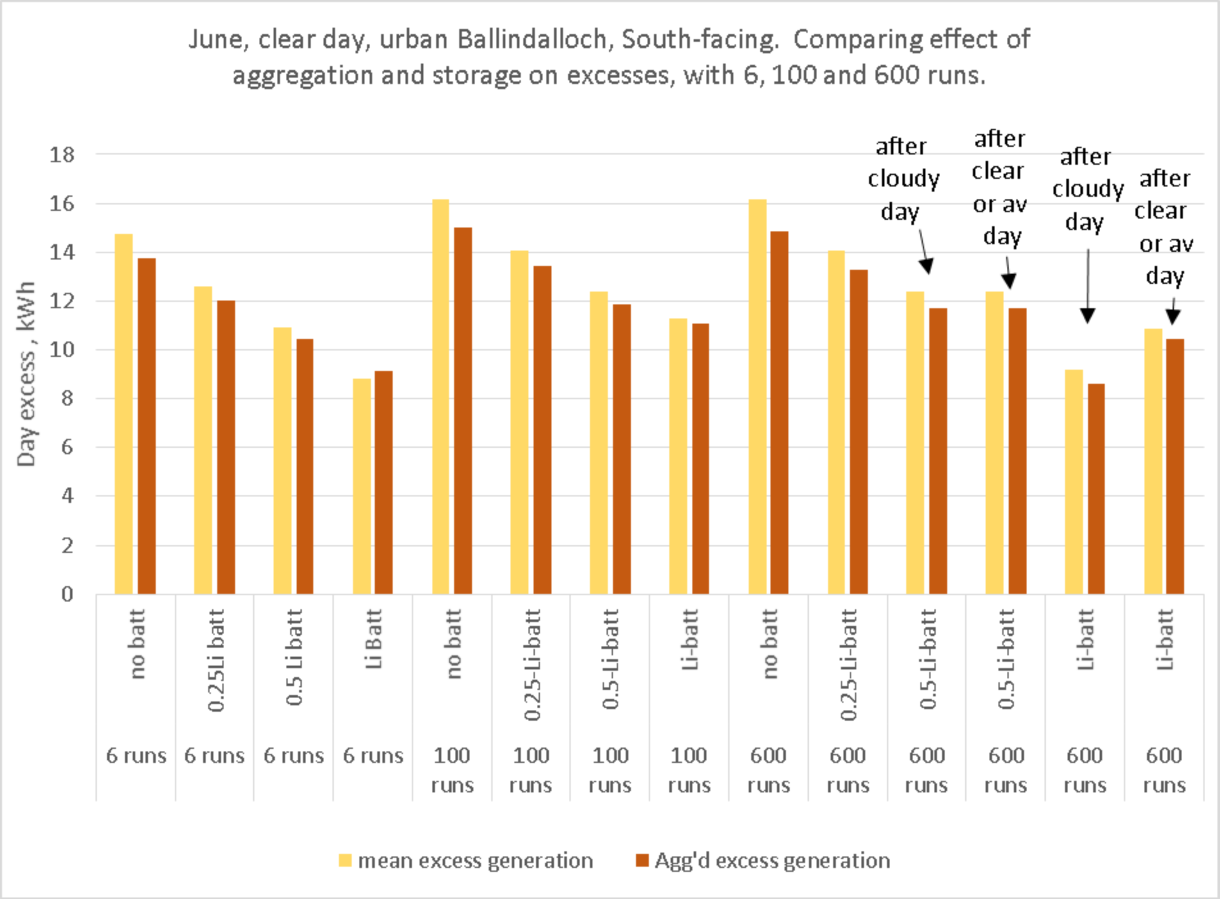

Clear day, January. Rural2. Deficits: mean of individual runs, and aggregated deficit, with varying Lithium battery storage
Deficit over the day, kWh
20
15
10
5
0
no batt
0.25 Li-batt
0.5 Li-batt
Li-batt
deficit mean
Agg'd deficit

APPENDIX 19 EFFECT OF NUMBERS OF RUNS, AND STORAGE, ON DEFICITS AND EXCESSES IN ELECTRICAL GENERATION. JUNE, BALLINDALLOCH SCENARIO, CLOUDY AND CLEAR DAY



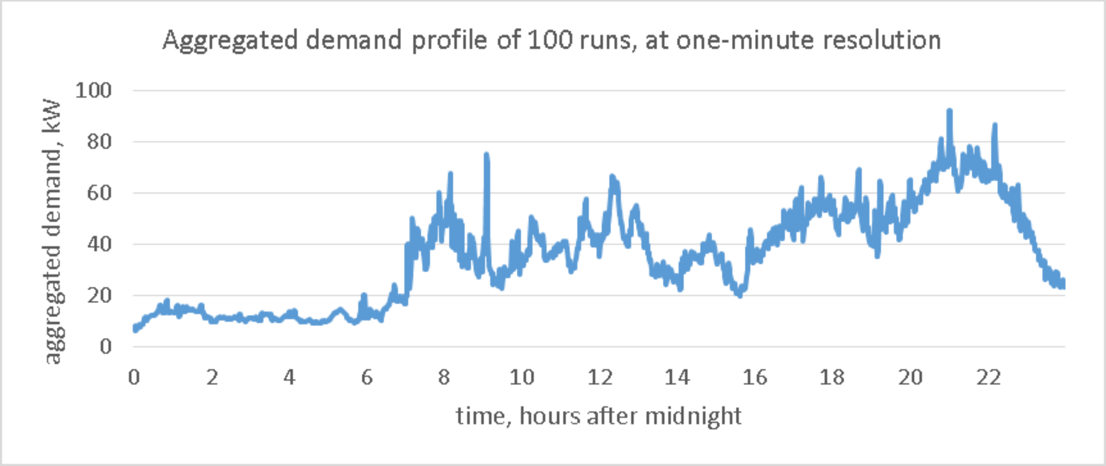


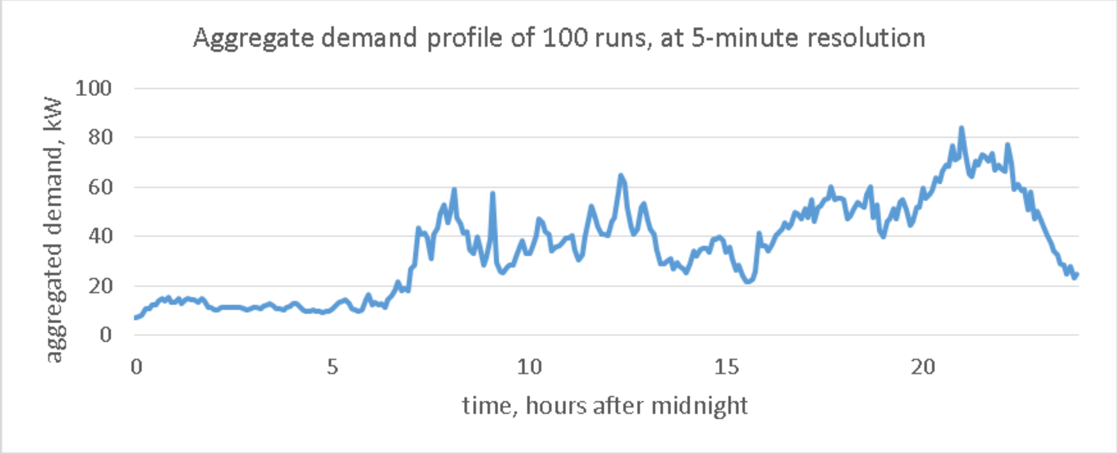

June cloudy day, urban Ballindalloch, south-facing. Comparing effect of aggregation and storage on excesses, with 6, 100 and 600 runs.

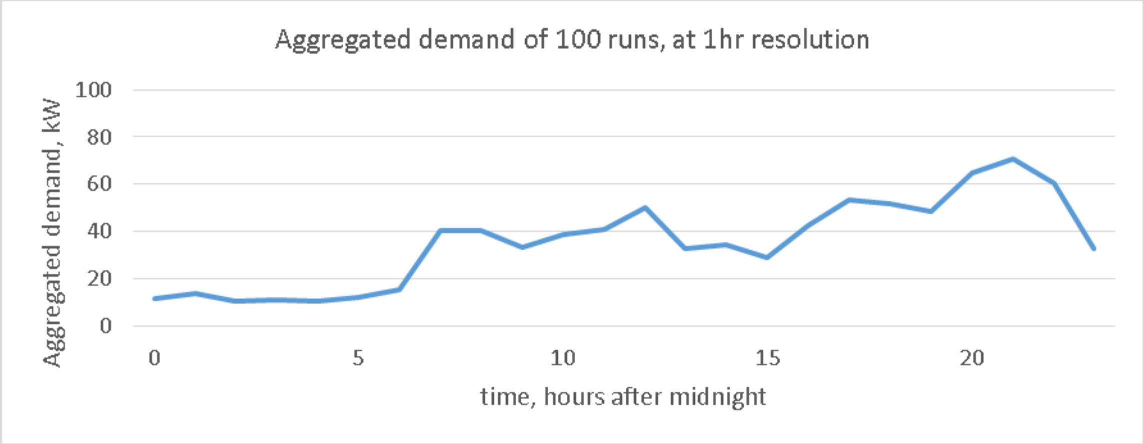

June, clear day, urban Ballindalloch, South-facing. Comparing effect of aggregation and storage on excesses, with 6, 100 and 600 runs.

APPENDIX 20 EFFECT OF TEMPORAL RESOLUTION ON GENERATION AND DEMAND PROFILES, AND CALCULATED EXCESSES AND DEFICITS

For the urban Ballindalloch scenario, June, aggregated demand profiles, were compared: in their original 1-minute resolution, and smoothed to 5 minute and one hour resolution.

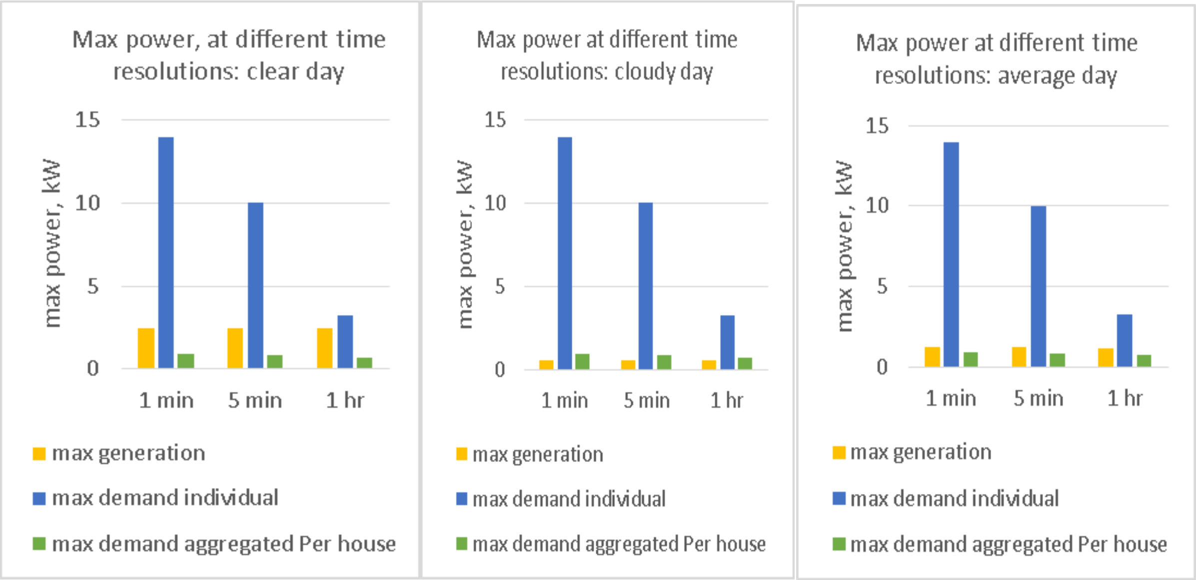




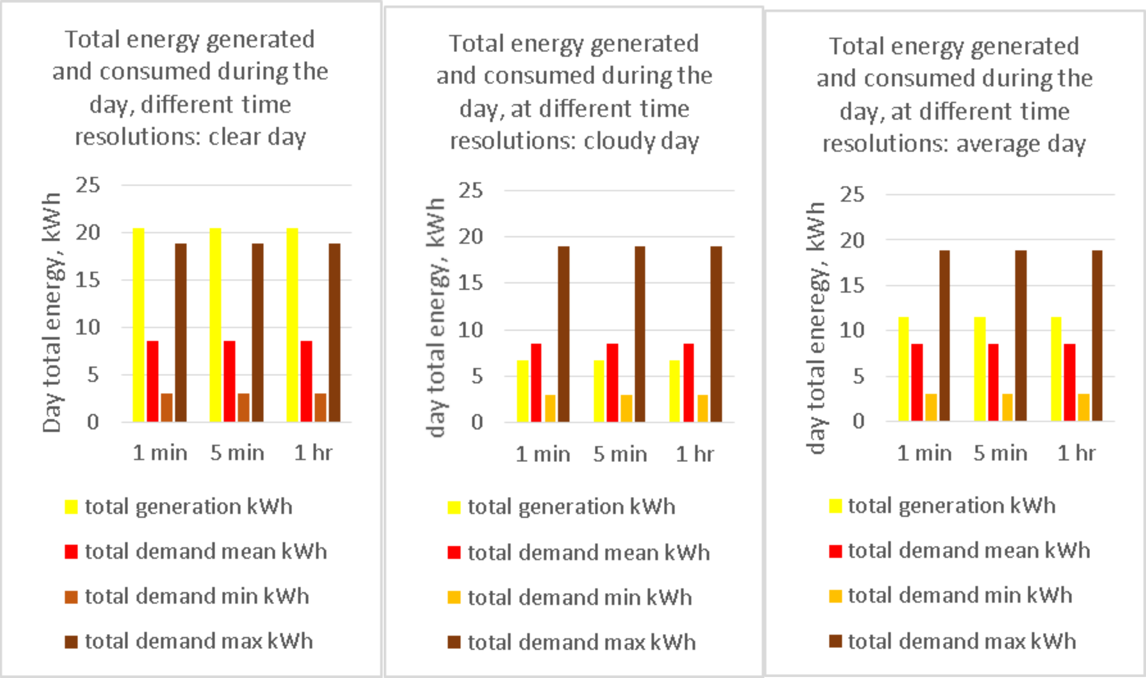


For the same runs, power generation and demand, and excesses and deficits in generation were calcuating, for a June, south-facing, urban Ballindalloch scenario, for the same three temporal resolutions. Results for clear, cloudy and average days are shown separately.

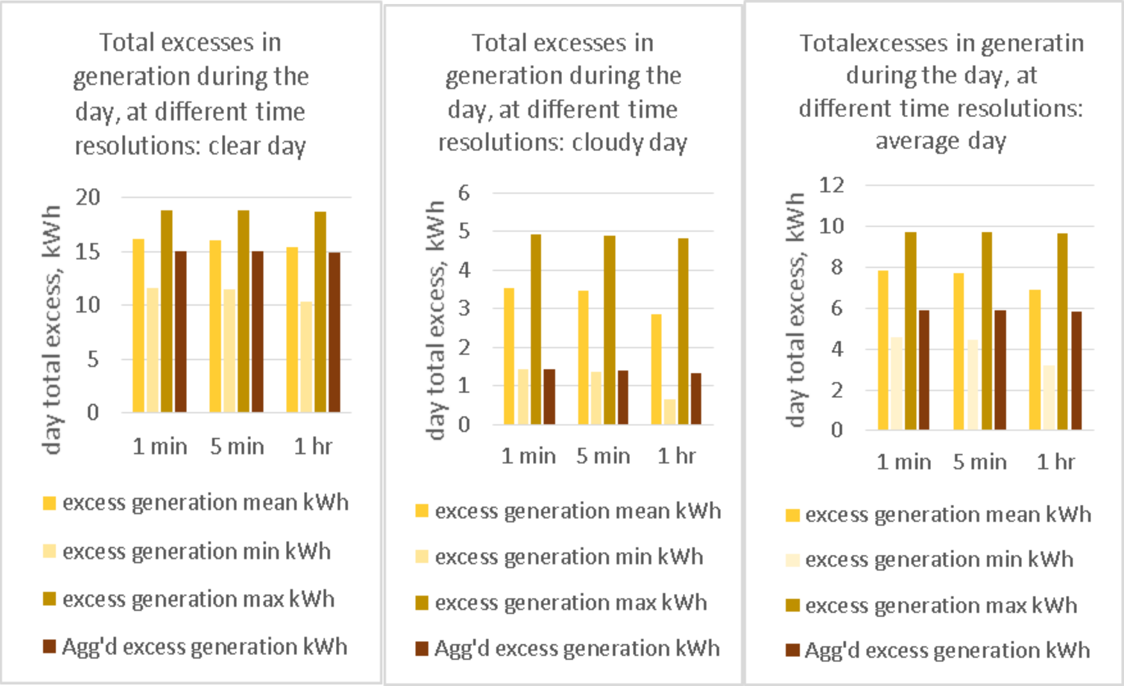
Comparison of peak power generation, and demand, during the day, for individual and aggregated runs, at different time resolutions: clear, cloudy and average day



Total energy generation and demand during the day, at different time resolutions, clear, cloudy and average day:



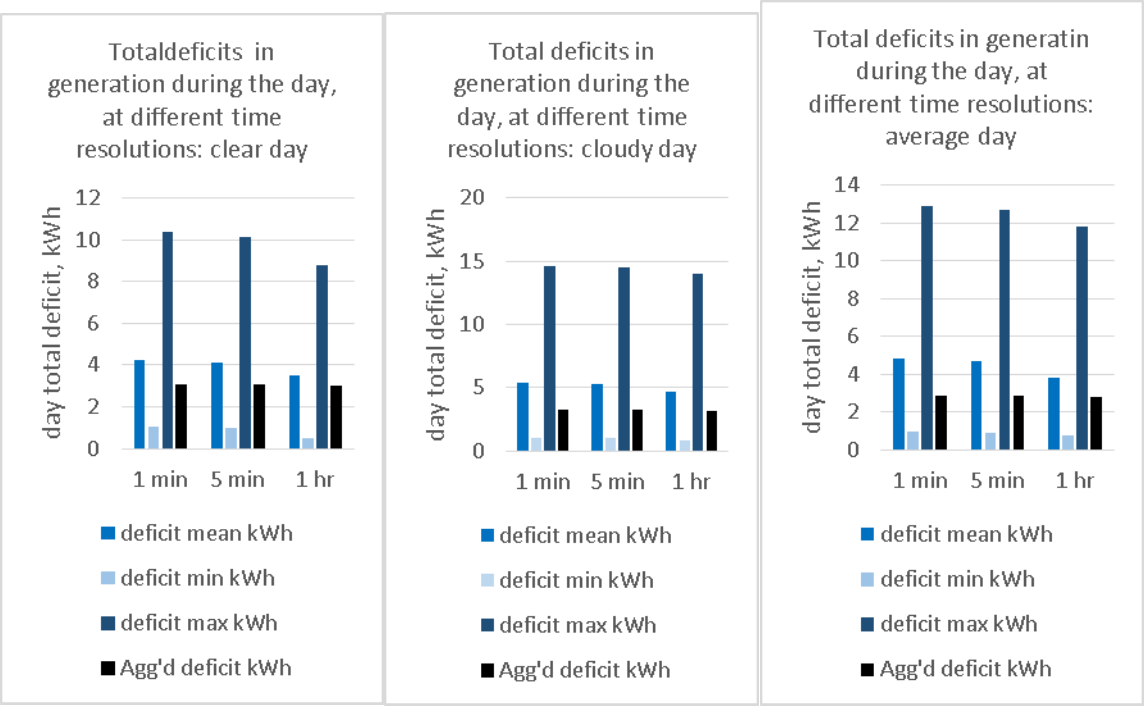
Day total excesses in generation: mean, minimum, and maximum of individual runs, and excess of all runs aggregated, at different time resolutions, on clear, cloudy and average days.


Total excesses in generation during the day, at different time resolutions: clear day

Total excesses in generation during the day, at different time resolutions: cloudy day

Totalexcesses in generatin during the day, at different time resolutions: average day

Day total deficits in generation: mean, minimum, and maximum of individual runs, and excess of all runs aggregated, at different time resolutions, on clear, cloudy and average days.


Totaldeficits in generation during the day, at different time resolutions: clear day

Total deficits in generation during the day, at different time resolutions: cloudy day

Total deficits in generatin during the day, at different time resolutions: average day

APPENDIX 21 CASE STUDY: MEASURED DATA FROM FINDHORN

Data was for the following dates:

Winter: 22/12/2015. Summer: 22/7/2015

ORIGIN Tags (datasets) used in modelling:

Winter:

1176, 1179, 1250, 1253, 1271, 1274, 1324, 1327, 1425, 1428, 1458, 1461, 1540, 1543, 1547, 1550, 1843, 1846, 1850, 1853, 1897, 1898, 1899, 1900, 1901, 1902, 1909, 1912, 3995, 3998, 4159, 4162, 4703, 4706, 4865, 4868, 5143, 5146, 6489, 6492, 6503, 6506, 6605, 6608, 7010.

Total number of properties: 16

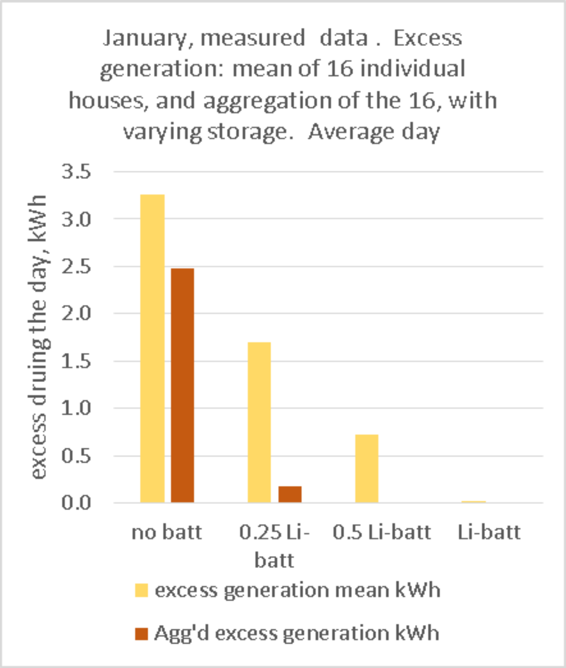
Summer:

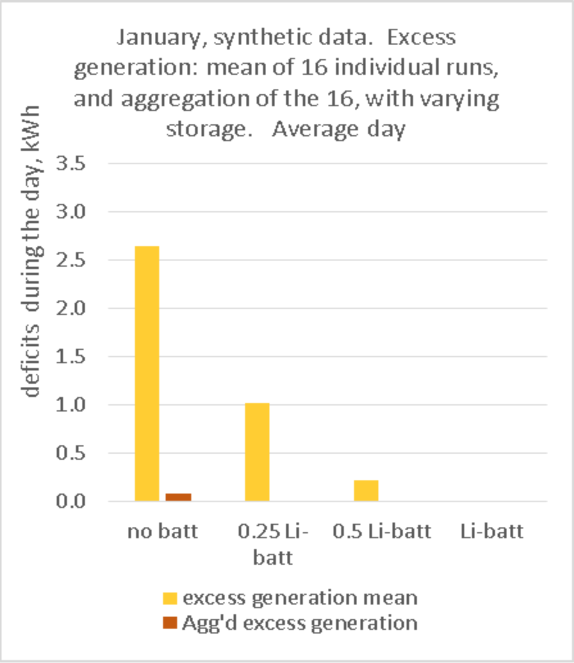
1029, 1032, 1176, 1179, 1250, 1253, 1271, 1274, 1324, 1327, 1344, 1347, 1398, 1401, 1425, 1428, 1438, 1441, 1458, 1461, 1524, 1525, 1526, 1527, 1528, 1529, 1540, 1543, 1547, 1550, 1843, 1846, 1850, 1853, 1897, 1898, 1899, 1900, 1901, 1902, 1909, 1912,2532, 2535, 3661, 3664, 3995, 3998, 4018, 4021, 4041, 4044, 4076, 4079, 4159, 4162, 4266, 4269, 4332, 4335, 4703, 4706, 4865, 4868, 5143, 5146, 6233, 6236, 6489, 6492, 6503, 6506, 6605, 6608, 6999, 7002, 7010.

Total number of properties: 31

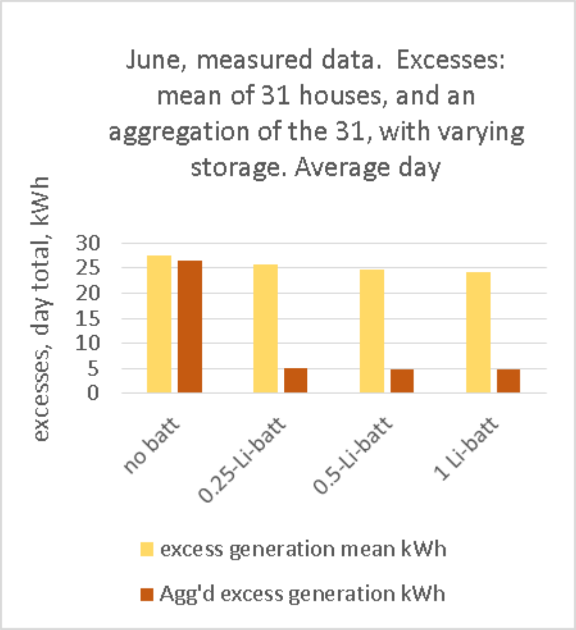
Day total excesses in generation (mean of all the individual runs, and an aggregation of all the runs), calculated from measured and synthetic data, are shown below.

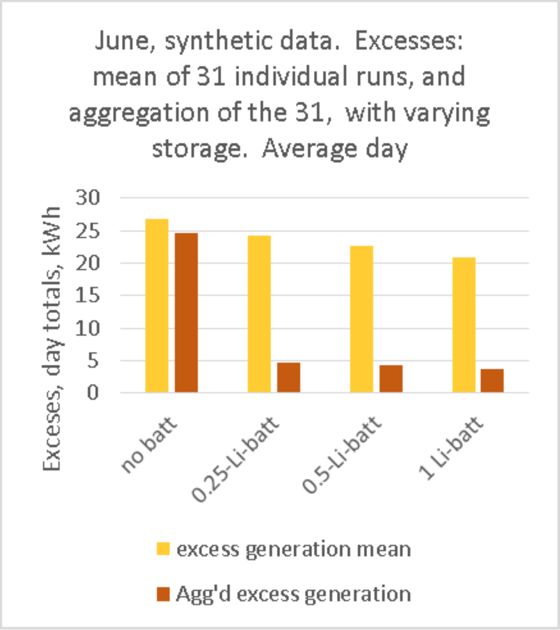
Winter





Summer


June, measured data. Excesses: mean of 31 houses, and an aggregation of the 31, with varying storage. Average day
excesses, day total, kWh
30
25
20
15
10
5
0
no batt
0.25-Li-batt
0.5-Li-batt
1 Li-batt
excess generation mean kWh
Agg'd excess generation kWh

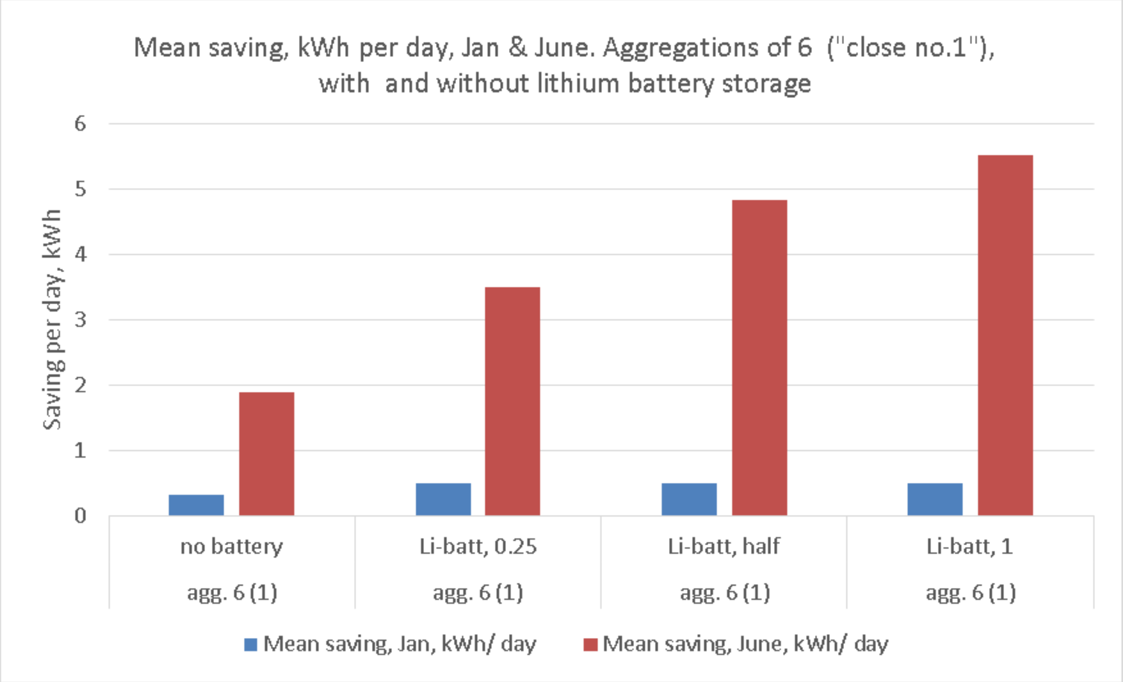

June, synthetic data. Excesses: mean of 31 individual runs, and aggregation of the 31, with varying storage. Average day
Exceses, day totals, kWh
30
25
20
15
10
5
0
no batt
0.25-Li-batt
0.5-Li-batt
1 Li-batt
excess generation mean
Agg'd excess generation

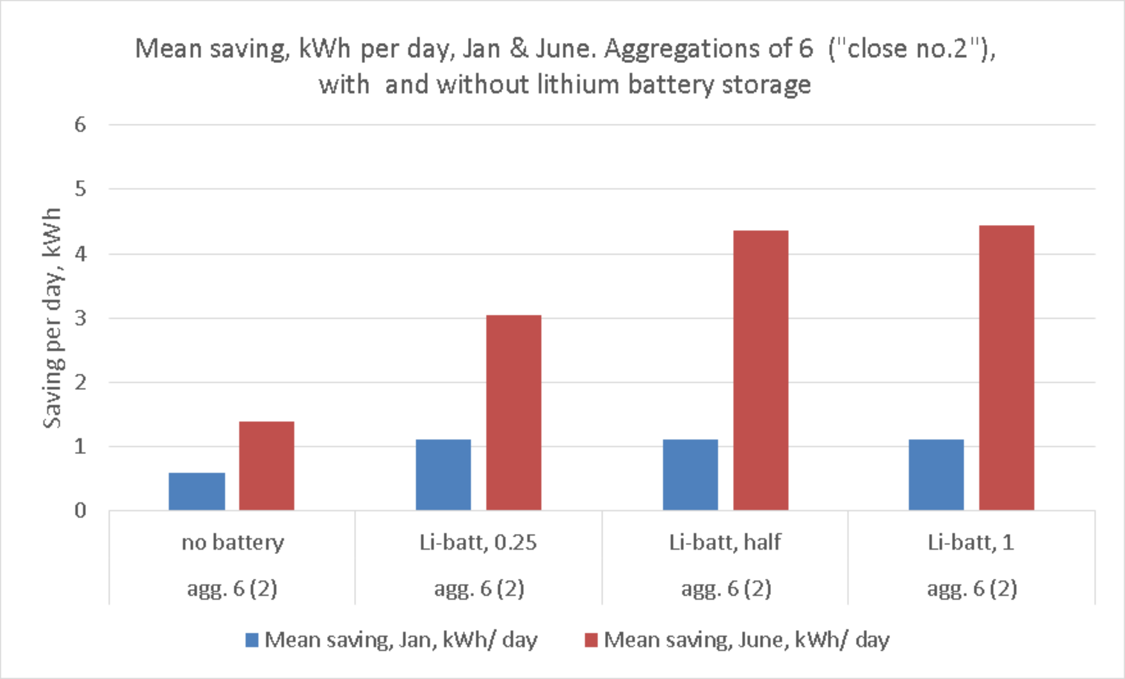
APPENDIX 22 POTENTIAL DEFICIT SAVINGS BY INSTALLING STORAGE AND AGGREGATION

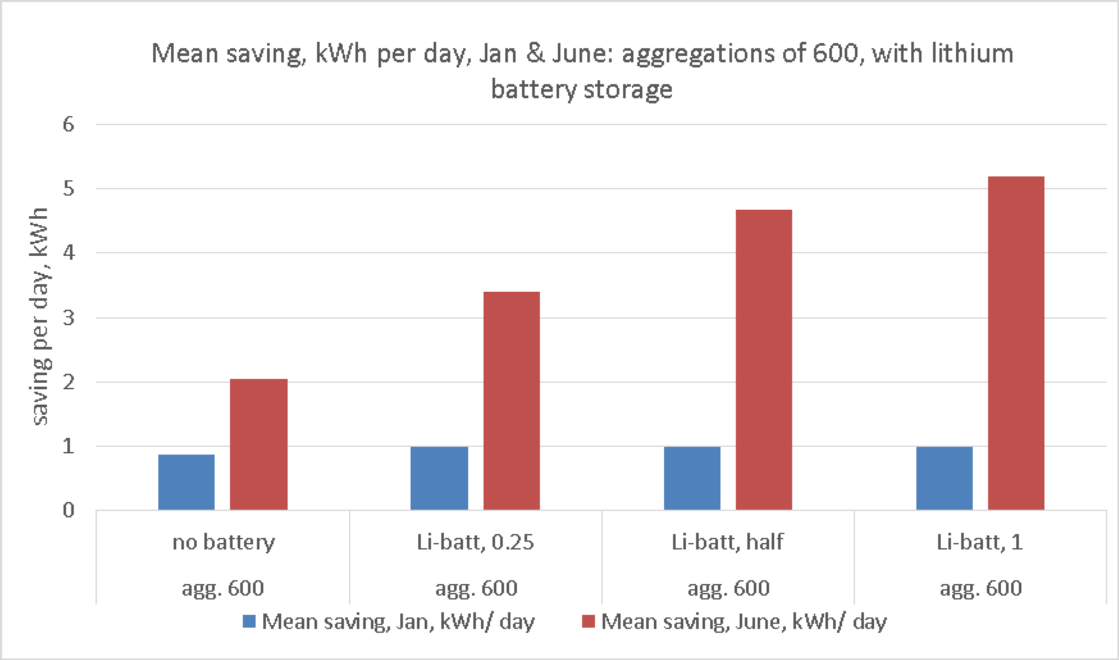
Day total deficit savings, January and June

Urban Ballindalloch scenario, south facing, average day following an average day.

Mean saving, kWh per day, installing varying lithium battery storage (including none) on aggregations of 6 (“close no.1” and “close no.2”) and 600.

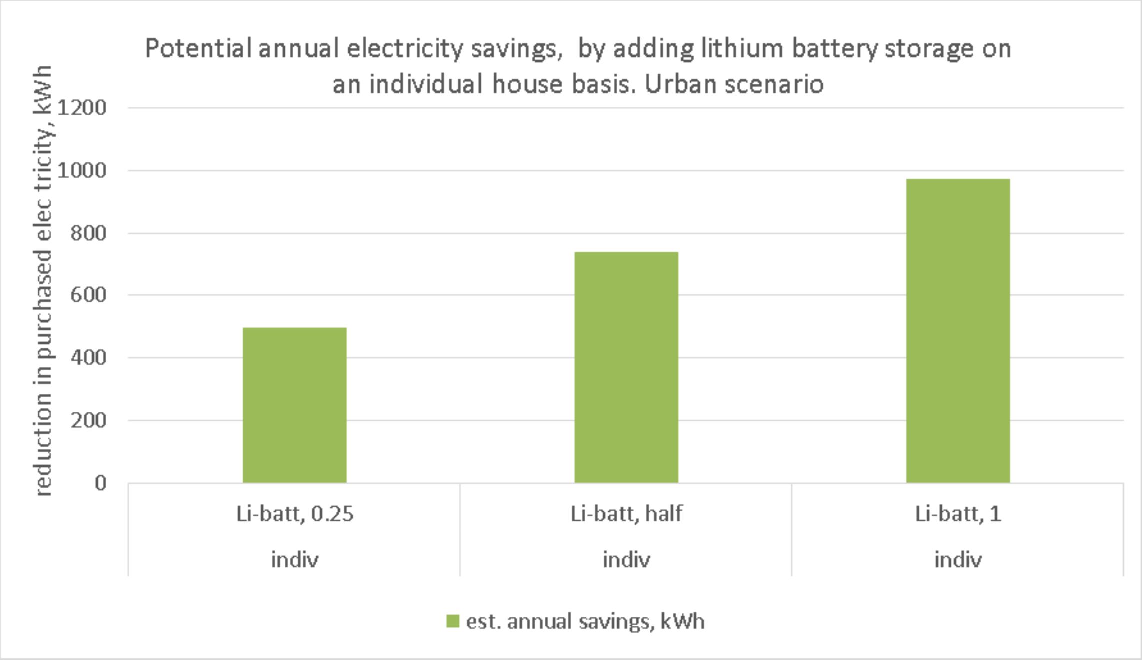


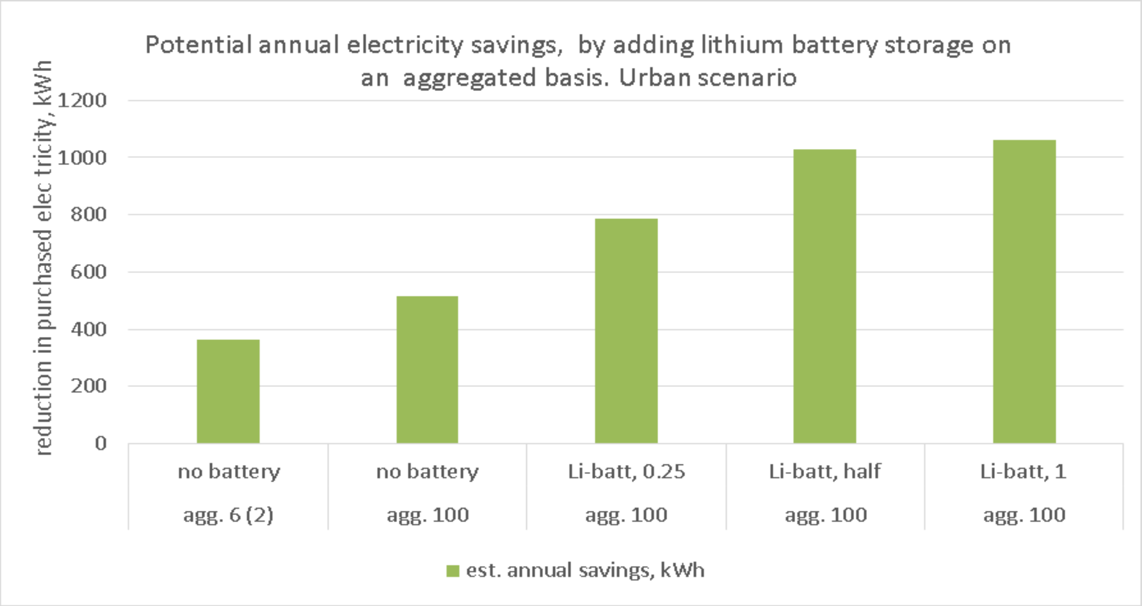



Mean saving, kWh per day, Jan & June: aggregations of 600, with lithium battery storage
saving per day, kWh
0
1
2
3
4
5
6
no battery
agg. 600
Li-batt, 0.25
agg. 600
Li-batt, half
agg. 600
Li-batt, 1
agg. 600
Mean saving, Jan, kWh/ day
Mean saving, June, kWh/ day

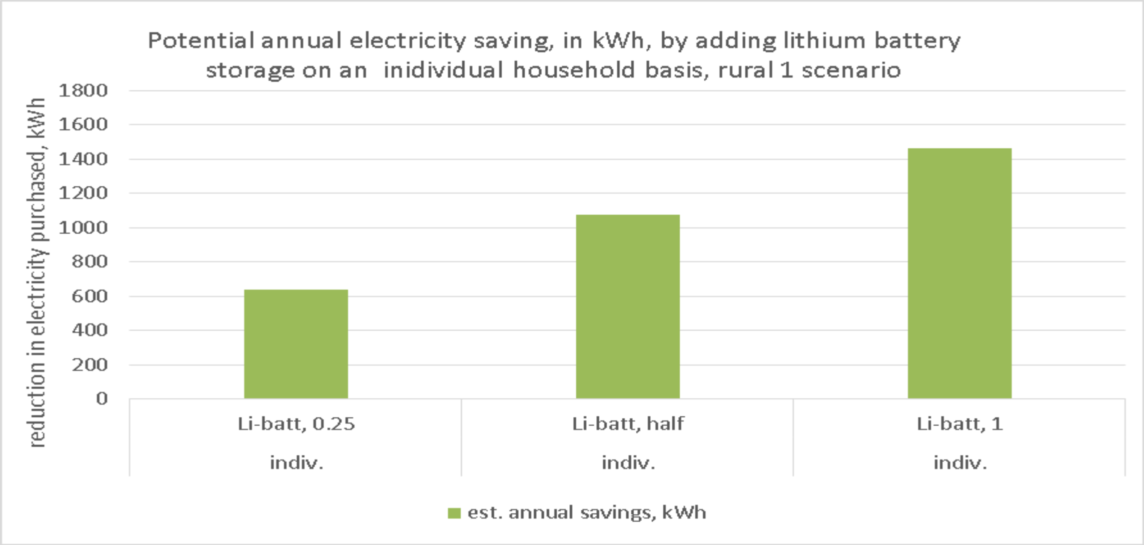
APPENDIX 23 ESTIMATED ANNUAL ELECTRICITY SAVINGS, KWH

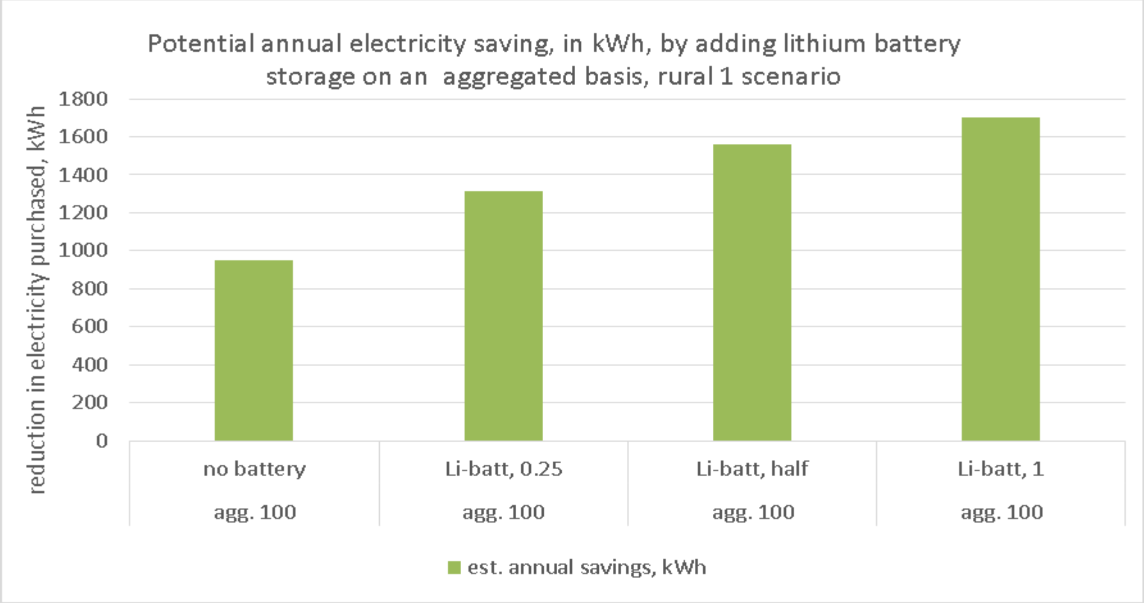
Urban scenario





Rural scenario

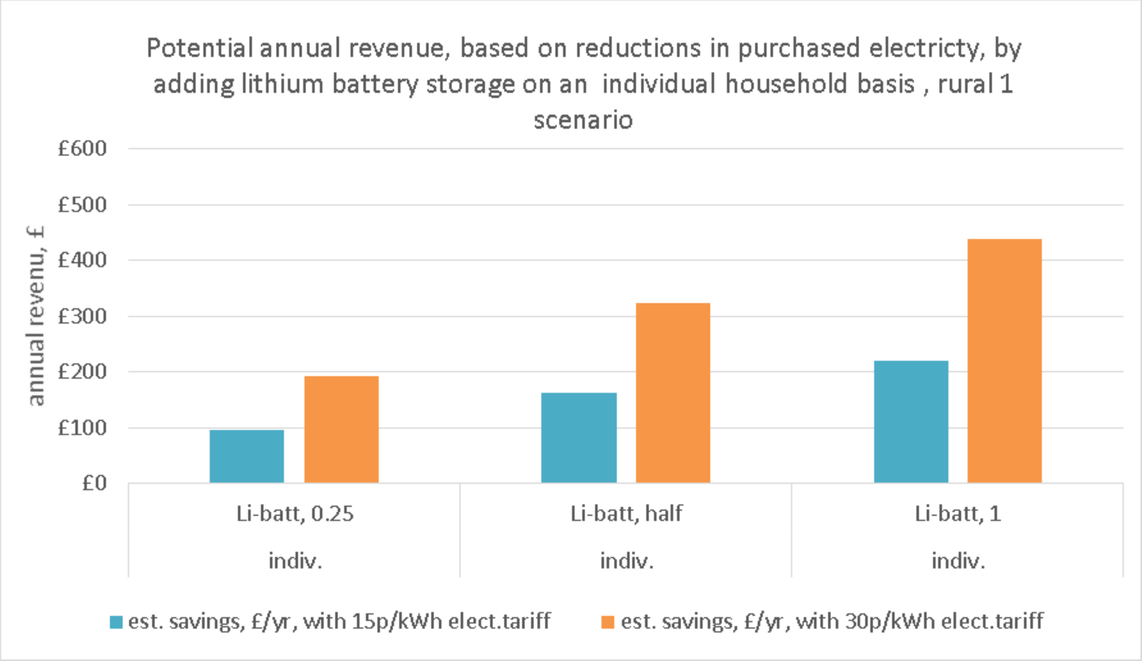




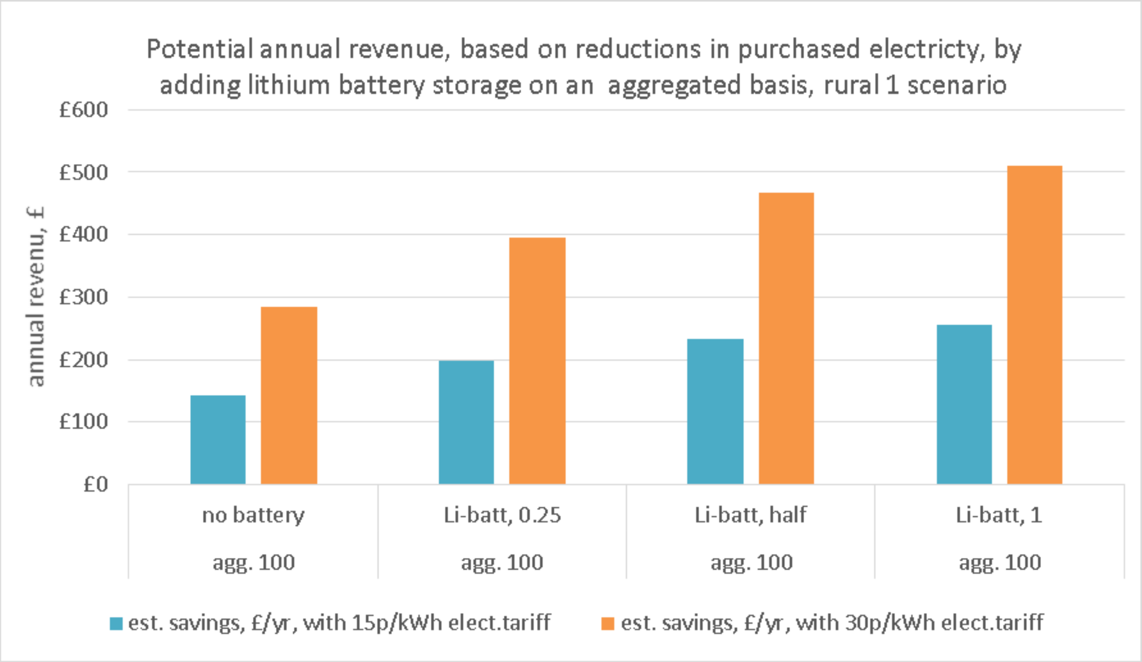
APPENDIX 24 EFFECT OF STORAGE AND AGGREGATION ON ANNUAL ELECTRICITY BILLS, RURAL 1 SCENARIO.

Tariff scenarios: scenario 1 – 15 pence / kWh; scenario 2 – 30 pence /kWh

Potential saving on annual electricity bill, by the installation of storage on an individual basis.



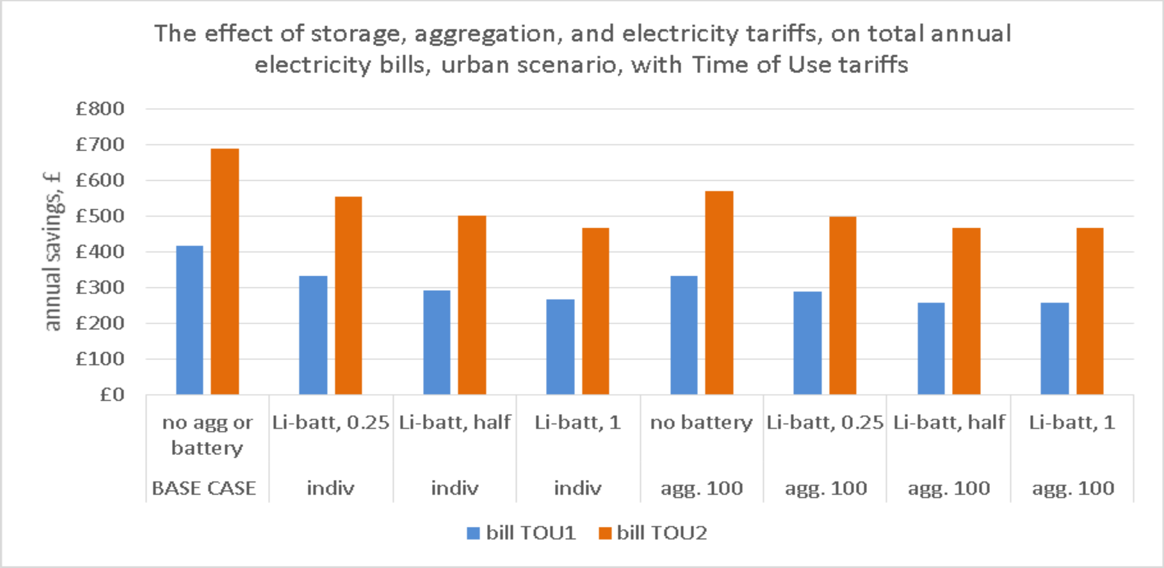
Potential saving on annual electricity bill, by the installation of storage in combination with aggregation of 100 houses



APPENDIX 25 TOTAL ANNUAL ELECTRICITY COSTS, WITH TIME OF USE ELECTRICITY TARIFFS, URBAN SCENARIO, WITH AND WITHOUT THE ABILITY TO SELL TO THE GRID AT PEAK TIMES.

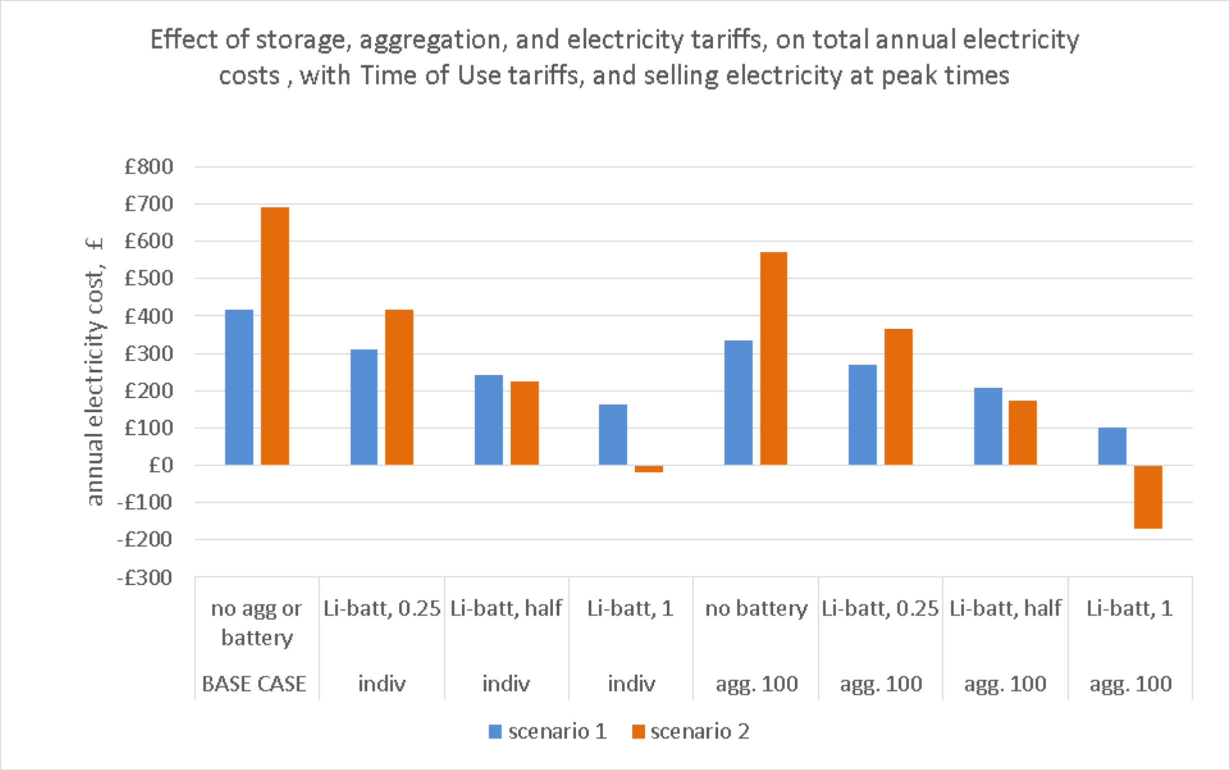
The graphs below present estimated annual electricity bills, for urban scenarios, in which there are variable Time of Use electricity tariffs. Scenario 1 is the present (15p/kWh), and scenario 2 is a future scenario, (30p/kWh)

Estimated annual electricity costs, urban scenario, with variable Time of Use electricity tariffs.



A further scenario was considered, in which electricity may be sold to the grid, at peak times only. Here, it was assumed export tariff was slightly lower than the peak rate import tariff. Scenario 1 has a peak rate tariff of 30 pence / kWh (purchase), and 25 pence / kWh (sale). Scenario 2 is a more futuristic scenario, with a peak rate tariff of £1 (purchase) and 80pence (sale) per kWh. Estimated annual electricity bill, with variable tariffs, and exports, are shown below.

Estimated annual electricity costs, urban scenario, with variable Time of Use electricity tariffs, and the ability to sell electricity to the grid at peak times.



APPENDIX 26 COMPARISON OF ESTIMATED ANNUAL REVENUE AND CAPITAL COSTS FROM IMPLEMENTATION OF STORAGE SYSTEMS

Urban scenario, electricity tariff scenarios 2: flat rate, TOU tariffs, and TOU with sale to the grid.

Battery no. & type	Individual / aggregated	Estimated annual revenue, £	Estimated capital cost, £ *(battery purchase only)*			
			Lead battery	Lithium battery		
		Flat rate tariff, scenario 2 (30p /kWh)	Battery cost, from industry (**Error! eference source not found.**)	Battery cost, from industry (**Error! eference source not found.**)	Battery cost, Teng, 2015	*Battery cost, Teng, 2020*
0.25 Li or 1 Pb	Indiv.	£160	£500	~£1500	£840	*£420*
0.5 Li or 2Pb	Indiv.	£230	£1000	£2000	£1680	*£840*
1 Li or 4 Pb	Indiv.	£290	£2000	£3000-£4000	£3360	*£1680*
0.25 Li or 1 Pb	Agg'd 100	£240	£500	~£1500	£840	*£420*
0.5 Li or 2 Pb	Agg'd 100	£310	£1000	£2000	£1680	*£840*
1 Li or 4 Pb	Agg'd 100	£320	£2000	£3000-£4000	£3360	*£1680*
No batt.	Agg'd 100 only	£150	£0	£0	£0	£0
No batt	Agg'd 6 only	£100-120	£0	£0	£0	£0

Urban scenario, electricity tariff TOU scenarios: TOU scenario 2, and TOU with sale to the grid scenario 2.

Battery no. & type	Individual / aggregated	Estimated annual revenue, £		Estimated capital cost, £ *(battery purchase only)*			
		TOU tariff scenario 2	TOU & sell to grid, scenario 2	Lead battery	Lithium battery		
				Battery cost, from industry (**Error! Reference source not found.**)	Battery cost, from industry (**Error! Reference source not found.**)	Battery cost, Teng, 2015	*Battery cost, Teng, 2020*
0.25 Li or 1 Pb	Indiv.	£130	£270	£500	~£1500	£840	*£420*
0.5 Li or 2Pb	Indiv.	£190	£470	£1000	£2000	£1680	*£840*
1 Li or 4 Pb	Indiv.	£220	£710	£2000	£3000-£4000	£3360	*£1680*
No batt.	Agg'd 100 only	£120	£120	£0	£0	£0	£0
0.25 Li or 1 Pb	Agg'd 100	£190	£330	£500	~£1500	£840	*£420*
0.5 Li or 2 Pb	Agg'd 100	£220	£520	£1000	£2000	£1680	*£840*
1 Li or 4 Pb	Agg'd 100	£220	£860	£2000	£3000-£4000	£3360	*£1680*

Rural 1 scenario, electricity tariff scenarios 2 (flat rate only).

Battery no. & type	Indiv-idual / aggre-gated	Est. annual revenue	Estimated capital cost, £ (battery purchase only)			
			Lead battery	Lithium battery		
		Flat rate tariff, scenario 2 (15p /kWh)	Battery cost, from industry (**Error! Reference source not found.**)	Battery cost, from industry (**Error! Reference source not found.**)	Battery cost, Teng, 2015	*Battery cost, Teng, 2020*
0.25 Li or 1 Pb batt	Indiv.	£190	£500	~£1500	£840	*£420*
0.5 Li batt	Indiv.	£320	£1000	£2000	£1680	*£840*
1 Li batt	Indiv.	£440	£2000	£3000-£4000	£3360	*£1680*
No battery	Agg'd 100	£280	£0	£0	£0	£0
0.25 Li batt	Agg'd 100	£400	£500	~£1500	£840	*£420*
0.5 Li batt	Agg'd 100	£440	£1000	£2000	£1680	*£840*
1 Li batt	Agg'd 100	£510	£2000	£3000-£4000	£3360	*£1680*