Evaluating consumer investments in distributed energy technologies

Giorgio Castagneto Gissey [a], *Behnam Zakeri* [a,b,c,d], *Paul E. Dodds* [a], *Dina Subkhankulova* [a]

The adoption of key sustainable technologies by end-users, mainly solar photovoltaic or electrical energy storage, strongly depends on their economic attractiveness, which is typically assessed with metrics of future cash flow, especially Net Present Value (NPV). Yet analyses using NPV typically do not consider the time-dependent evolution of electricity systems in the short- and long-terms. We show this to be of critical importance toward accurately calculating the profitability of these technologies.

By linking an energy system model with a power system model, we observe substantial differences between NPV estimates calculated with and without representing potential evolutions of the electricity system. Our results suggest that not accounting for short- and long-run changes in the electricity system could underestimate the NPV of an investment in photovoltaic and storage by around 20%, especially in scenarios with high levels of renewables, moderate flexibility, and high electrification in the system. Using system-dependent cash flow metrics can have a major impact on end-users' understanding of energy technology profitability.

Keywords: feasibility study; prosumer; private investment; system value; energy storage and solar PV, renewable energy integration.

[a] UCL Energy Institute, University College London; [b] The Laboratory of Energy Efficiency and Systems, Aalto University, Finland; [c] Sustainable Energy Planning, Department of Planning, Aalborg University Copenhagen, Denmark; [d] International Institute for Applied Systems Analysis (IIASA), Austria.

* Corresponding Author: Dr Giorgio Castagneto Gissey, Senior Research Associate, UCL; +44(0)2031085978; g.castagneto-gissey@ucl.ac.uk. Address: UCL Energy Institute; Central House; 14 Upper Woburn Place; London; WC1H 0NN; United Kingdom.

Highlights:

- Cash flow metrics are commonly used to evaluate the financial viability of energy investments
- Such analyses typically neglect the time-varying nature of energy supply and demand
- We derive an electricity system-based Net Present Value (NPV) for distributed technologies
- NPV can be underestimated by 20% in a system with high renewable energy and highly electrified
- Using system-based NPV (SNPV) can improve perceived attractiveness of energy investments

1 Introduction

Many governments are subsidizing renewable energy-based electricity generation to meet national energy and environmental policies and reducing greenhouse gas emissions (Williams *et al.*, 2012). More decentralized energy systems are evolving (UKERC, 2018), and solar photovoltaic (PV) has been widely deployed in many countries over recent years (DECC, 2016). Solar PV generation does not usually correlate with peak electricity demand (Pfenninger and Staffell, 2016), especially in high-latitude countries such as the UK. Hence, electrical energy storage (EES) is being pursued as a key option to shift excess electricity generated during the day to meet evening peak demand (Ofgem, 2013; US Department of Energy, 2013). This will help end users improve their energy independence and minimize the curtailment of renewable energy (Li et al., 2019). Yet, the adoption of solar PV and/or EES onsite depends on the financial benefits those investments can offer to end users (Borenstein, 2017; Hoppmann *et al.*, 2014; Rodrigues *et al.*, 2016; O'Shaughnessy *et al.*, 2018a,b).

Current metrics used to assess the financial benefit of these technologies are based on net discounted cash flow, with Net Present Value (NPV) the most widely used (Chesser *et al.*, 2018; Comello *et al.*, 2018). Yet, unless these metrics are backed by a representation of the underlying electricity system, they do not account for possible changes over time in energy supply and demand, distorting the perception of value of these technologies to consumers. This could potentially mislead the investment decisions of consumers, resulting in suboptimal policies and a reduction in private and social welfare. Distributed energy technologies such as solar PV and EES can improve the affordability, security and sustainability of electricity supply for consumers who operate these technologies, as well as the whole electricity system. Hence, ensuring that such investments are financially attractive will be critical toward their deployment and success of related energy policies.

In this paper, we show that evaluations of the profitability of solar PV and EES that account for changes over time in the underlying electricity system lead to very different conclusions to those that do not. We develop a holistic modelling framework to compare how differently one would perceive the financial viability of an investment in these technologies in the presence or absence of detailed electricity system modelling. In so doing, we demonstrate the importance of considering short- and long-run changes in electricity supply and demand, as these largely affect the value of distributed energy technologies over time.

1.1 Metrics to evaluate investments in distributed energy technologies

Different metrics can be applied to evaluate the economic feasibility of investments in distributed energy technologies, either from the investor's (electricity consumer) or the system-level viewpoint. In a study comparing different feed-in-tariff (FiT) schemes for solar PV, the total cost-revenues of the system is annualized for different FiT assumptions, and a payback period is estimated for the consumer's investment (Muhammad-Sukki *et al.*, 2011). Considering the opportunity cost of investment in distributed renewable energy technologies is another method to account for system-level environmental and social benefits of such technologies. For example, the economic profitability of solar PV can be estimated by calculating the levelized cost of each unit of electricity (LCOE) from fossil fuel sources being replaced by solar PV (opportunity cost) (Ramadhan and Naseeb, 2011). Poullikkas (2009) applies a parametric cost-benefit analysis that accounts for different up-front capital, module characteristics, as well as a proxy for carbon emissions being mitigated by installing solar PV. Different metrics of cost-benefit analyses of solar PV for consumers are compared in O'Shaughnessy *et al.* (2018).

NPV is a well-known metric used to calculate the monetary value of an investment in solar PV and EES (Cucchiella *et al.*, 2016; Dietrich and Weber, 2018; Hoppmann *et al.*, 2014). NPV is the difference between the present value of cash inflows and outflows over a certain time period. These cash inflows and outflows depend on the supply, demand and price of wholesale electricity, among other factors. Consumers are not always exposed to day-to-day price volatility, as electricity retailers buy from wholesale markets and sell electricity with different tariffs both at a fixed or volatile price to consumers. Nevertheless, consumer prices are revised every week (dynamic) or 3 months (static) as wholesale prices vary, depending on the pricing scheme. More dynamic pricing schemes such as time-of-use (ToU) or even hourly tariffs are being adopted in different countries to mobilize demand response and promote peak shaving.

Return on Investment (ROI) and Internal Rate of Return (IRR) are also commonly used metrics to analyze the cost-benefit of investment in distributed energy technologies (Benis et al., 2018). ROI is a measure of the return on a particular investment relative to the investment's cost, while IRR is the rate of growth a project is expected to generate. Relevant examples using either metric are Padmanathan *et al.* (2017) and Formica and Pecht (2017), respectively.

To assess the financial case of a consumer's investment in EES (or PV, or both), studies typically compare the cost of electricity for consumers with and without the technology, where EES is used to increase the uptake of onsite PV-generated electricity. Bost *et al.* (2011) use the 'grid parity' concept to evaluate the profitability of PV and storage by considering the levelized electricity cost. A similar approach is taken by Braun *et al.* (2009) and Colmenar-Santos *et al.* (2012), who calculate IRR of hypothetical EES investments. A few studies (Bost *et al.*, 2011; Braun *et al.*, 2009; Clastres *et al.*, 2010; Hoppmann *et al.*, 2014) compute revenues from storage and PV investments.

1.2 Using the metrics: accuracy and perspective

NPV and other measures of discounted cash flows, including ROI and IRR, are widely used to determine the profitability of solar PV and EES. These metrics compare the energy costs of consumers against income generated from electricity sales to the grid. Although these metrics are regularly used to inform governments, consumers, and energy companies about the expected value of these technologies, we have identified two important deficiencies in the way they are used for this purpose:

- *Accuracy.* Cost-benefit studies (e.g. Li *et al.*, 2019; Ross, 2018; Schwarz *et al.*, 2018) do not directly account for short- and long-run changes in the price of electricity for consumers, i.e. households and commercial/industrial end users, who ultimately pay the price either dynamically or through monthly or quarterly updated tariffs. Bost *et al.* (2011) and most of the studies reviewed in Hoppmann *et al.* (2014) assume electricity prices levels or variations to be fixed in time, which is the same as assuming an invariant electricity system. These studies do not consider changes in the supply and demand of electricity in the wider electricity system over time and under different scenarios. By not applying an electricity system model for this purpose, studies (e.g. Boampong and Brown, 2020) do not incorporate a detailed representation of the underlying electricity system and its future development. Other examples include Muhammad-Sukki et al. (2011), who compare the feasibility of investments in solar PV in the UK and Malaysia by applying exogenously assumed FiT values over the lifetime of the technology, while Boampong and Brown (2020) apply exogenous electricity prices, and Martin and Rice (2018) consult stakeholders to derive future FiT rates.
- *Perspective.* Studies typically consider a simple business case that does not reflect a certain evolution of the energy system into the future. In other words, the electricity system is assumed virtually static in time. For example, they consider a certain power capacity mix (Ramadhan and Naseeb, 2011) or are based on present day power grid characteristics (Martin and Rice, 2018). Those studies that do assume that the system will evolve implement changes as exogenous model assumptions, for example as a set of predefined future electricity prices or tariffs (Boampong and Brown, 2020).

In the future, the move to low-carbon generation, and a loss of flexible generation (caused by high renewable deployments), could lead to both (i) higher overall electricity prices and (ii) substantially greater price volatility. Yet a consistent implicit assumption of these studies assessing the private value of distributed energy technologies (here, solar PV and EES) is that the electricity system will remain static, with most authors assuming a constant increase in retail prices over time (Hoppmann *et al.*, 2014; O'Shaughnessy et al., 2018; Varghese and Sioshansi, 2020).

In this study, we propose a variant of NPV called *System NPV* (SNPV), which is defined as the NPV of a distributed energy technology based on a certain evolution path of the electricity system. The metric introduced in this work is used to account for the wide variations in the electricity price that occur over time (Joskow, 2011), which we hypothesise will have a profound impact on the monetary value of distributed technologies to consumers.

1.3 Aims and structure of the paper

The paper aims to determine how differently a consumer would evaluate the monetary benefit of investing in solar PV and EES if it considers the underlying future evolution of the energy system. Using an electricity dispatch model to address the accuracy and perspective deficiencies of past studies, we measure how important it is to consider the potential future evolutions of the whole energy system. We show that accounting for changes in the electricity system over the short- and long-runs is critical to accurately identify the value of distributed energy technologies to consumers who invest in them.

This study focuses on NPV because it is the most commonly used and understood metric, yet the lessons from our work extend to all other widely used metrics, as they are based on discounted cash flows. The remainder of this paper is structured as follows. Section 2 describes the methodology and data. Section 3 reports our main results, which are discussed in Section 4. Conclusions are drawn in Section 5.

2 Methods

2.1 Deriving future electricity prices and tariffs

Although wholesale electricity prices vary over time, electricity supply companies have traditionally held the risk from this volatility and charge consumers fixed prices per kWh of electricity consumed. Over periods of months, changes in wholesale prices are passed through to electricity consumers integrating them into retail prices and electricity tariffs. More recently, flexible dynamic tariffs are increasingly being introduced exposing consumers to more dynamic pricing schemes. In either case, the main component of consumers' electricity bills is the wholesale cost (Ofgem, 2017). To get a full understanding of how wholesale costs affect the NPV (or other metrics) related to a consumer's energy technology investment, one needs to compute wholesale electricity prices for future energy scenarios, then transform them into retail prices, and finally estimate the electricity tariffs paid by consumers for buying electricity.

We focus on the value of consumer investments in solar PV and EES, optimizing the consumer's monetary utility based on the lifetime of the individual systems. Modelling electricity demand in the wholesale market over long periods requires the use of an energy system model to represent changes in electricity demand and in the electricity generation portfolio. We therefore soft-link an energy system model, UK TIMES (UKTM) to a power system model to calculate equilibrium prices in the electricity wholesale market, using a similar modelling approach to Castagneto Gissey and Dodds (2017). By this soft-linkage, fuel prices, annual electricity demand, and power generation capacities under different energy scenarios will be fed as input to the electricity dispatch model. The electricity dispatch model, which has a high tempo-spatial resolution of the GB electricity system, is then run with the specified capacities to meet electricity demand. The output, which is hourly wholesale electricity prices is used to calculate the retail prices as shown in Appendix F. Figure 1 illustrates the overall methodology.

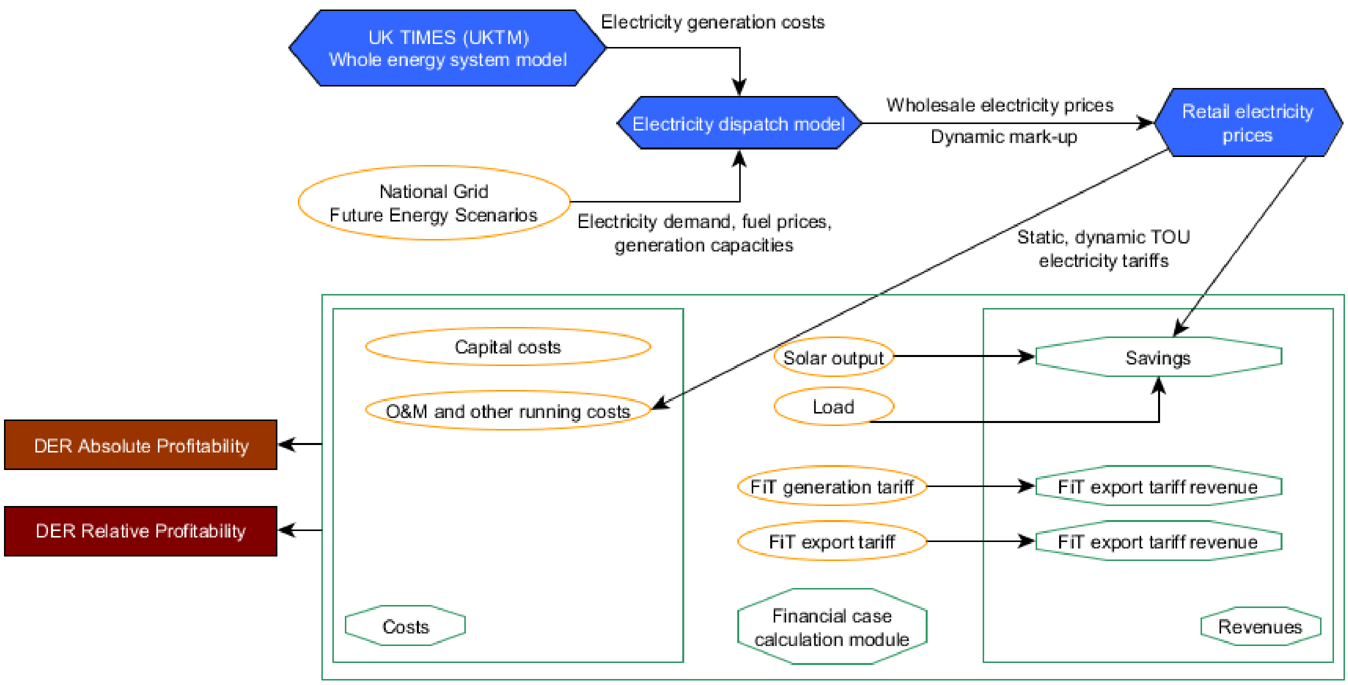

Figure 1. Relationship between model components. Key: Hexagon-shaped structures are models; ellipse-shaped structures are modelling inputs and data; rectangular-shaped structures are model outputs; octagonal-shaped structures are calculation modules; and, arrows indicate how model components feed into one another.

2.2 Power system model and Future Energy Scenarios

We model the UK power system by using the following data and assumptions. Electricity generation costs are from the UK TIMES energy system model (UKTM) (UCL, 2014), while electricity demand, generation capacities, and fuel prices are from National Grid's whole energy system model scenarios (National Grid, 2016). National Grid is the owner of the high-voltage power transmission network in England and Wales, who due to its position is in contact with different stakeholders, including the private sector and the public. We consider four distinct evolutions of the energy system from National Grid's Future Energy Scenarios in 2016 (FES16). We chose this set of scenarios as National Grid has developed these by conducting an extensive data collection and stakeholder engagement involving more than 362 organizations in the process. Moreover, these scenarios cover a wide range of futures represented in a matrix with two dimensions of Green Ambition and Prosperity. The document describing these scenarios has been reviewed by the GB Office of Gas and Electricity Markets (Ofgem), the National Regulatory Authority in this domain, stating that a wide range of views have been taken into account. They include:

1. *Gone Green*, which presents an ambitious renewable expansion scenario where national renewable targets are met;
2. *Consumer Power*, in which energy security and reducing generation costs are primary concerns;
3. *Slow Progression*, where there is a reduced progression towards decarbonization; and
4. *No Progression*, where the generation portfolio is relatively unchanged.

Table 1 reports the key statistics for each scenario in a sample year, 2030. Gone Green has the largest generation share from renewables and storage capacity, while it also has the lowest fossil generation and carbon intensity. No Progression is similar to the existing energy system and has the lowest values in all these areas. The other two scenarios lie in between.

	GoneGreen	Slow Progression	No Progression	Consumer Power
Annual demand (TWh)	346	318	322	331
Peak demand (GW)	67	59	61	63
Total installed capacity (GW)	165	131	114	157
Low carbon capacity (GW)	103	78	53	87
Interconnector capacity (GW)	23	15	11	23
Electricity storage capacity (GW)	12	5	3	17
Fossil fuel capacity (GW)	20	31	47	33
Renewable energy (%)	31	27	21	23
Reduction in carbon emissions (%)	58	53	48	49

Table 1. Key electricity statistics relative to each FES scenario in 2030 (National Grid, 2016).

Gone Green meets electricity demand by 2040 with 34% of the total share coming from renewables due to the growth of wind, bioenergy and PV. The slower progress in the building and transport sectors implies the scenarios reach the UK's overall target of 15% renewable energy later than the EU-agreed 2020 deadline, ranging between 2022 in Gone Green and 2029 in No Progression. Modelling the electricity system and various future scenarios will be used to understand the extent to which the NPV of PV, EES, or a combined PV+EES investment might vary.

The examined scenarios have different underlying socio-economic assumptions that derive the society's approach to energy use resulting in different values for electricity demand. In the Slow Progression scenario, end users are knowledgeable about their energy use and green technologies and look for opportunities to reduce their energy use and associated emissions. As such, electricity demand is the lowest compared to other scenarios. In the No Progression scenario, however, energy users focus on reducing the cost of their bills adopting business as usual with little interest in green products and little incentive to replace old products until they break. Heating and transport demands are mainly met by traditional methods, with little progress in electrification. On the other end, Gone Green represents a society that is active in reducing emissions. Hence, knowledge on green technologies and the adoption rates are high, including in the electrification of the transport and heating sectors. This results in high installation rates of home energy management systems and domestic batteries, and an increased electricity demand overall.

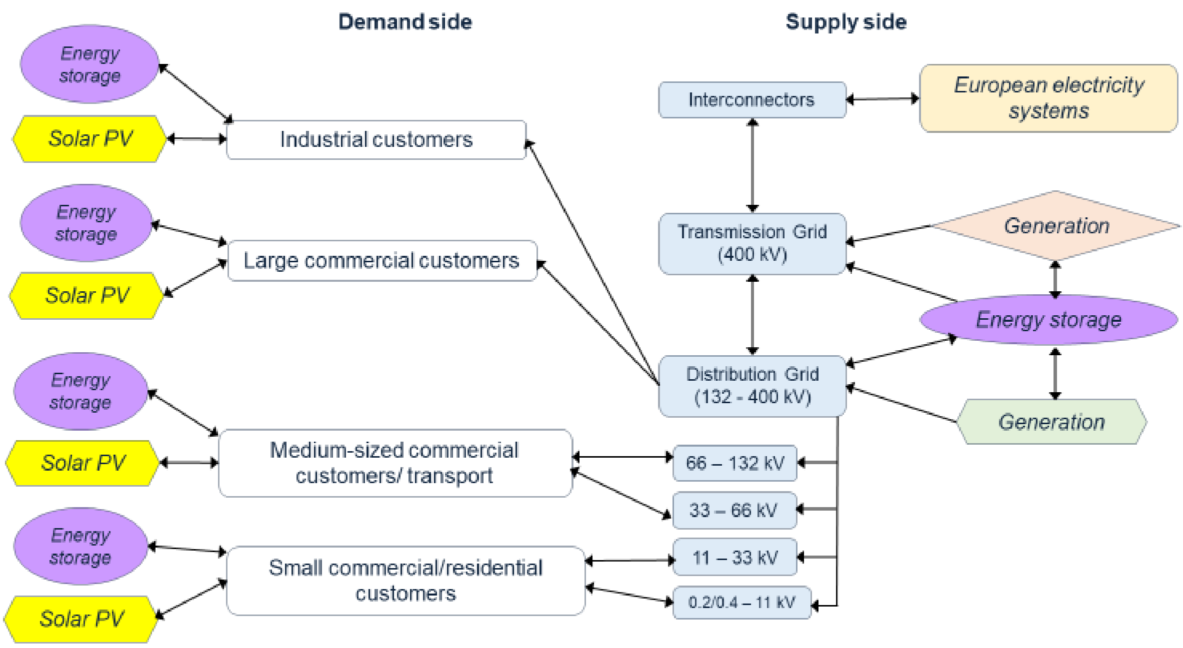

Figure 2. Representation of electricity flows in the GB electricity grid in the ESMA model.

We use a novel electricity system management model, ESMA (Castagneto Gissey *et al.*, 2019) with the electricity system structured as illustrated in Figure 2. Detailed information about ESMA is provided in Appendices A–H in the Supporting Information. ESMA minimizes electricity costs and calculates electricity wholesale prices under the assumption of consumers' self-operation of their solar PV and energy storage devices (see Appendix E). Retail prices are calculated by assuming a time-varying mark-up over the marginal cost of retail supply, or the wholesale price, which proportionally accounts for network fees, taxes, and other costs (Ofgem, 2017). More information about our methodology for calculating wholesale and retail electricity prices is in Appendix F. Retail prices are used to derive static and dynamic time-of-use (TOU) electricity tariffs following calibration on historical tariff data (ONS, 2015).

2.3 The consumer

We consider the profitability of solar PV and EES, both alone and in combination, for a UK domestic electricity consumer under different evolutions of the system. Solar PV generation and electricity consumption are based on a typical UK consumer, and vary by hour. We model a three-bedroom dwelling with a load profile displaying mean percentage night consumption of 30% and 55% under static and Economy7 TOU tariffs, respectively (Ofgem, 2013). This type of household has an annual electricity consumption between 3,084-4,399 kWh/a (on average 71-79 kWh/m^2/a) based on UK Electricity Survey Data[1]. The household's electricity bill is sensitive to both the load profile and solar generation in cases where the consumer is assumed to operate a solar PV system. The average load factor for solar PV in the UK is between12-13% in 2015-2019. The peak load occurs typically between 5-8 PM in weekdays and seasonally in a winter evening. We account for intra-day, monthly and seasonal variations in these variables.

Consumers using solar PV are assumed to receive the generation and export feed-in tariff (FiT) subsidies, and no subsidies at all in one case. We assume a generation tariff of £0.049 kWh^{-1} decreasing on an annual basis as specified by Ofgem (2016). The export tariff is assumed to pay £0.043 kWh^{-1} for electricity exports to the grid (Boxwell, 2017). In scenarios where the consumer operates PV and/or EES, we consider a 4-kW polycrystalline PV system, and a 6.4 kWh–3.3 kW EES stationary battery, with a lifetime limit of 5,000 cycles and a maximum of one cycle a day.

Note also that the use of FiTs does not affect the relevance of the research questions examined in this paper because we control for future wholesale prices, which are considered in both NPV and SNPV calculations. Because FiT was regularly updated by Ofgem based on different parameters, especially wholesale electricity prices, in our analysis we base the future retail prices on the computed wholesale electricity prices. Based on the computed retail prices, we then derive the tariffs for importing electricity from the grid. This is done by calibration using historical data to form static and dynamic time-of-use (TOU) electricity tariffs for each future scenario. While these depend on the supplier, UK National Statistics (ONS, 2015) provides national averages. Static tariffs are assumed as £0.15 kWh^{-1}, and dynamic TOU tariffs refer to the UK program Economy7 with an overnight off-peak (24–7h) tariff of £0.07 kWh^{-1} and an on-peak (7–24h) tariff of £0.16 kWh^{-1} (ONS, 2015). While Economy7 was designed for storage heating, they are time-dependent and are suitable for microgenerators. We assume that future static tariffs vary quarterly according to the quarterly mean electricity wholesale price, while TOU day and night tariff levels are proportional to the static tariff (see Table 2).

1 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/208097/10043_R66141HouseholdElectricitySurveyFinalReportissue4.pdf

Tariff scheme	Base value, 2016 (kWh^{-1})	Future value
Static	0.15£	Based on quarterly average of modeled electricity prices*
Dynamic (ToU) (Economy7)	Night (0-7h): 0.07£ Day (7-24h): 0.16£	Proportional to corresponding static tariff
* These prices are endogenously calculated from the results of the electricity system model for the future years		

Table 2. Different feed-in-tariff (FiT) schemes examined today and in future.

2.3.1. Operation of technologies on the consumer side

The consumer operating PV and/or EES is assumed to minimize their hourly operational electricity cost, which comprises the cost of net electricity purchased from the grid in addition to that of running EES for each discharge cycle. In a "No Technology" scenario, with neither a battery nor a solar PV system, the consumer simply pays the relevant electricity tariff. When only owning a battery, in the "EES-only" case, the consumer will pay a retail electricity price for charging the battery. Therefore, investing in a battery does not provide additional savings under a Static tariff as there is no difference between the price of electricity when charging and discharging. However, in the TOU tariff case, the battery can be charged during off-peak hours (24-7h) at the lower night-time tariff to discharge during peak hours (7-24h) when the price is at the higher day-time rate (£0.16/kWh) (National Statistics, 2015). This process continues on a daily basis until 5,000 cycles are reached, at which point the battery will be obsolete and must be replaced at an additional cost, which is assumed to be 70% lower than the 2016 level in 2029 (DNV GL, 2016).

In a "PV-only" case, only solar PV is invested, and no battery is owned by the consumer. In this scenario, the consumer simply utilizes electricity from solar when this is available, at a zero-marginal cost, and exports the surplus of PV generation to the grid at £0.049/kWh during each half-hour. In the "PV+EES" scenario, the customer owns both a battery and a solar PV system. Therefore, at times when PV generation exceeds load, any excess electricity is utilized to charge the storage device. Once the battery is fully charged, the remaining excess electricity generation is then exported back to the grid. Electricity that is stored during the day is used during the evening when solar generation falls below the load level, thereby providing the consumer with additional savings by avoiding relatively expensive imports from the grid at peak hours, maximizing self-consumption from the PV system.

Further details about the consumer's cost optimization model are given in Appendix G, whereas data used in this model is described in Appendix H. The model's formulation iterates the optimization for day-long periods. This assumption reflects the fact that, under TOU tariffs, the lower rate arises during the off-peak period, which is suitable for charging the storage system. The consumer therefore ensures that the asset is optimally operated each day.

2.4 Modelling scenarios

We calculate NPV for four consumer technology combinations: (1) no technology; (2) an EES system alone; (3) a solar PV system alone; and (4) a combined solar PV and EES system (PV+EES). We also examine the use of both static and dynamic TOU tariffs, and four potential evolutions of the future energy and power system: (i) Gone Green; (ii) Consumer Power; (iii) Slow Progression; and, (iv) No Progression.

2.5 Electricity bills and financial case

Annual electricity costs are estimated based on a simple accounting exercise and are calculated for each scenario relative to the reference case (1), in which the consumer pays static tariffs that grow 5% per year (Braun *et al.*, 2009; Kaldellis *et al.*, 2009) and has neither generation nor storage assets. Investment and management costs, and other data used in this study, are reported in Appendix H. Based on the cost optimization model, the consumer minimizes electricity costs every hour. We assess the financial case for PV+EES, yielding the NPV of the investment for each scenario. Hourly savings, and other revenues and costs, are then aggregated to an annual level to yield NPV. We assume no debt financing and investment costs arising in January 2015, with a technology-optimal horizon of 26 years to 2040. The starting year of 2015 was chosen in line with data linked to the ESMA model (see Appendices A-D). The discount rate is assumed at 5% per year, following CCC (2013).

In scenarios where solar PV is present (Scenarios 3 and 4), we consider a typical, 3.99 kW polycrystalline system, because PV systems under 4 kW are eligible for feed-in tariffs (Department of Energy and Climate Change, 2013). (Department of Energy and Climate Change, 2013), producing averages of 0.8 kW at peak output and 8.92 kWh per day total output, corresponding to 3,256 kWh of electricity generated per year. Solar generation data is derived using monthly data from the Energy Saving Trust (2011). The cost of a typical domestic solar PV system is estimated at £8,080 (Department of Energy and Climate Change, 2013)[2]. In terms of variable costs, we considered £1,000 for inverters with a 10 year-lifetime, insurance of £7/month (The Eco Experts, 2016), and 90% efficiency (SolarTherm UK, 2016). Additional costs include one-off payments for grid usage of £101 per year and for grid connection of £80 (EDF Energy, 2016). A typical solar PV system's lifetime is 20-25 years (National Renewable Energy Laboratory, 2016). Decreases in solar PV costs are by 70% relative to 2016 levels by 2030 (DNV GL, 2016).

Scenarios involving EES (Scenarios 2 and 4) employ data from Tesla (2016) with respect to the Tesla Powerwall v1, which was commercialized in late 2016. This is a 7 kWh-3.3 kW stationary battery, with round-trip efficiency of 92.5%, intended for daily cycle applications. We also considered an additional battery size of 13.5 kW. The battery's capital cost, including installation and necessary accessories[3], is £6,991 (SolarTherm UK, 2016). The battery's depreciation and its efficiency losses represent the main operating costs of the storage device. The battery is able to withstand a maximum of 5,000 cycles for a warrantied time period of 10 years, after which the purchase and installation of a new battery will be necessary (Zakeri and Syri, 2015). Hence, we assume a linear annual depreciation of the battery, which yields an annual cost of £5.48 yr^{-1} over Tesla's 10-year warrantied time period (calculated by the authors).

Assuming that one battery has a lifetime of 13 years (5,000 cycles), so that two batteries last 26 years, and that manufacturers usually offer solar panels along with a 20 to 25-year warrantied period, we fix the time horizon to 26 years, which is optimal from the perspective of the combination of the two technologies. This determines an optimal investment horizon of 26 years.

2.6 NPV and System NPV

The NPV of an investment is the difference between the present value of cash inflows and outflows over a given time period and is estimated for a given technology *P* as shown in Eq. 1:

$$NPV_P = \xi_P - \eta_P \qquad (1)$$

where the input parameter ξ_p is total discounted revenues in years $1 \ldots T$, and η_P showing the total discounted costs.

We define the 'System NPV' (SNPV) of an investment as the NPV calculated using an endogenous price of electricity throughout the calculation period. In the SNPV, the cost of importing electricity from the grid reflects a system-dependent electricity price, which is internally consistent with a future energy scenario representing a specific evolution of the electricity system. The opportunity cost of such an investment may be the net value of grid electricity imports (if the investment is in solar PV

[2] For installations sized between 0-4kW, the mean cost per kW was £2,020, which includes the cost of solar PV generation equipment, plus direct costs of fixing panels to roof/ground mount, any performance displays and connecting to electricity supply, including VAT.

[3] Accessories include the following items: 15no. P300 Power optimisers, 1 x S/E 3680 SolarEdge inverter, 1 x Wi fi unit and connection, 1 x Tesla Powerwall, 1 x StorEdge system and components, 1 x Connection to the SolarEdge portal, and necessary scaffolding.

or EES alone) or the net value of PV alone (if we are analyzing the viability of an investment in the integrated PV+EES system).

For an investment in a technology P*,* SNPV is then calculated through Eq. (2):

$$SNPV_P = SNPV(P) - SNPV(E) \qquad (2)$$

The input parameters in Eq. (2) are $SNPV(P)$ as the absolute SNPV of investing in technology P (gross of the SNPV of the discounted cost including the cost of electricity imports from the grid) and $SNPV(E)$ showing the SNPV of purchasing electricity from the grid without operating any electricity generation or storage technology. This accounts for the fact that consumers aim to invest in technology to minimize the cost of electricity, whereby grid imports are their second-best choice. The same line of reasoning is applied when calculating the associated NPV of an investment in solar PV.

A similar approach can be used to find the SNPV of an investment in EES or, in other words, the extra value contributed by EES when pairing solar PV with EES. This difference shows the value of storage as intended to increase the value of solar PV. The metrics could also be expressed as ratios, but considering differentials is more useful because it defines the excess monetary value relative to achieving break-even. Once again, we use the same approach when calculating the associated NPV of an investment in PV+EES.

In order to understand the degree by which using SNPV improves the accuracy of a technology's profitability measure, we compare SNPV with NPV. When considering NPV, we do not employ an electricity system model and simply assume that average electricity retail prices increase by 5% per year. This is based on a general practice in most studies evaluating technology profitability, such as Braun *et al.* (2009); Kaldellis *et al.* (2009);(Lyon, 2016; Ross, 2018; Schwarz et al., 2018). Hence, the main difference between SNPV and NPV in our analysis is that the price of electricity for SNPV is endogenous, i.e. calculated based on future energy scenarios and accounting for their impact on the electricity system, while in NPV the electricity prices are exogenous and are assumed to grow by 5% per year.

2.7 Model evaluation

We evaluate our model using sensitivity tests that vary several key input parameters. Following Hoppmann *et al.* (2014) and Castagneto Gissey and Dodds (2017), we consider the changes in the SNPV of an investment in PV+EES that are associated with changes in financial case components with the highest shares in total costs and revenues. In particular, we vary: the nominal discount rate; battery future investment costs; potential increases in global installed PV capacity; PV inverter costs; O&M costs for solar PV; and O&M costs for EES.

3 Results

In this Section, the results of our analysis are presented in two parts. First, we discuss the results of SNPV and compare that with a NPV analysis to understand the financial feasibility of investment in distributed energy technologies under different future scenarios for the energy system and retail tariffs. Second, we conduct a sensitivity analysis to evaluate the impact of main parameters on the results.

3.1 System NPV

Table 3 reports the System NPVs (SNPVs) for investments in different combination of distributed technologies, i.e., no investment, EES only, PV only, and PV+EES for a period between 2015 and 2040. The value of each investment is examined compared to a case with no investment, i.e., buying electricity entirely from the grid. The value of investment in each technology configuration is shown for two electricity tariffs, i.e., static and TOU, and under four different future scenarios for the energy system. Negative values indicate the unprofitability of that technology compared to the case buying electricity from the grid. These values are calculated without considering any subsidies for investment in distributed technologies.

Electricity tariff	Consumer technology	Future Energy Scenario							
		No Progression		Slow Progression		Gone Green		Consumer Power	
		$SNPV$ (£k)	$SNPV_P$ (£k)	$SNPV$ (£k)	$SNPV_P$ (£k)	$SNPV$ (£k)	$SNPV_P$ (£k)	$SNPV$ (£k)	$SNPV_P$ (£k)
Static	None	-9.5	N/A	-9.6	N/A	-8.8	N/A	-8.6	N/A
	EES-only	-16.2	-6.7	-16.4	-6.8	-15.0	-6.2	-14.7	-6.1
	PV-only	-10.9	-1.4	-11.0	-1.4	-10.1	-1.3	-9.8	-1.2
	PV+EES	-13.7	-4.2	-13.9	-4.3	-12.7	-3.9	-12.4	-3.8
TOU	None	-9.0	N/A	-9.2	N/A	-8.4	N/A	-8.1	N/A
	EES-only	-12.8	-3.8	-13.1	-3.9	-11.9	-3.5	-11.5	-3.4
	PV-only	-9.5	-0.5	-9.7	-0.5	-8.8	-0.4	-8.5	-0.4
	PV+EES	-13.3	-4.3	-13.6	-4.4	-12.4	-4.0	-12.0	-3.9

Table 3. System NPV (SNPV) indicators in £k. Investment value indicators are reported for each technology combination, type of electricity tariff, and future evolution of the energy system. (*SNPV:* absolute SNPV. $SNPV_P$ = Relative SNPV for a technology P: net of the value of that technology relative to the case of only importing electricity from the grid).

3.1.1 Individual energy technology investments

The estimated value (SNPV) of an energy technology for a consumer is the additional value of that technology compared to importing all of electricity needs from the grid, including the time value of the cost of this electricity imports.

In 2015, investment in solar PV was marginally unprofitable for the typical UK consumer and required an increase in its value relative to grid imports by between £0.4–1.4k to become profitable (see Table 3, results for PV-only). This occurs as a result of low insolation in the UK in combination with the typical consumer's load profile. The highest SNPV for solar PV-only relates to the Gone Green and Consumer Power scenarios, under TOU tariffs. This means that, in these scenarios, solar PV was at its closest to being profitable relative to simply importing electricity from the grid, by a margin of £400. Because grid imports were more expensive in these two scenarios, making on-site generation more profitable compared to buying electricity from the grid. The higher profitability of PV-only investments under TOU compared to a Static tariff is because of solar generation mostly occurring in peak hours with higher prices under TOU.

In general, it is clear that SNPV generally decreases as the consumer becomes more independent of the grid. The results also show that the SNPV of an investment in EES-only must have been between £3–7k for EES to have become a viable solution for the consumer when operated without solar PV. TOU tariff shows slightly better profitability compared to Static tariff when investing only on EES, as the price difference between day and night makes energy arbitrage possible in this case, even without onsite generation.

3.1.2 Pairing solar PV with EES

To show that pairing PV with EES was profitable for the consumer (or not), we consider the SNPV of an investment in PV+EES. When the consumer operates PV+EES, an additional £3.8–4.4k was required to achieve parity relative to grid imports (see Table 3, results for PV+EES). Similar to investment in PV-only, the consumer has a lower loss of value in the case of PV+EES under Gone Green and Consumer Power scenarios, a net value loss of £3.9-4.0 compared to £4.2-4.4 in No- and Slow Progression. However, opposite to the case of investment in PV-only, installing PV+EES is slightly more profitable under Static tariffs. EES is mainly deployed to store electricity generated by solar panels during the day and shift that to the evening and, in some days, to night hours. Because the price of electricity at night in Static tariff is almost double than that of TOU, using EES for day-to-night energy arbitrage makes more benefits for PV+EES under the Static tariff.

Comparing the value of the PV+EES system relative to that of an investment in PV alone, shows an increase in absolute SNPV of £2.6–3.8k is needed to enable the PV+EES system to be as valuable as an investment in PV alone. This could have been achieved by a subsidy of 36–56% of the capital cost of the first installed battery, which suggests that EES is not yet financially viable for a typical UK consumer.[4] This indicates that should UK authorities have subsidized around half of the capital cost of the initial battery (in 2015) required over the 26-year period, the PV+EES system could have reached parity with the value of grid imports.

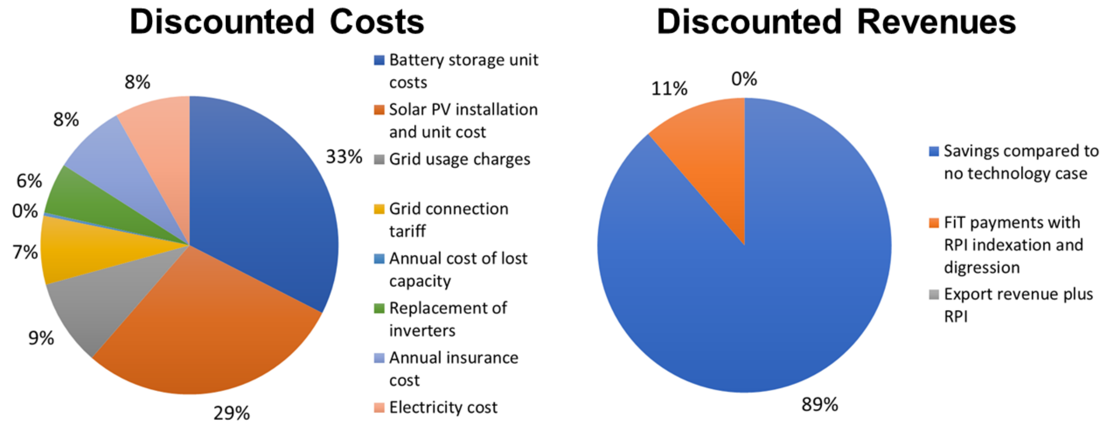

Figure 3. Typical component shares of discounted costs and revenues for an investment in PV+EES in 2015. Savings are calculated relative to the same consumer with no technology at its disposal (i.e. neither PV nor EES). The above example considers the case with FiTs.

Figure 3 shows the estimated breakdown of the discounted costs and revenues for a typical consumer operating a PV+EES system under TOU tariffs in 2015. Two batteries were required to store electricity from solar PV during the 26-year lifetime of the PV system, with the cost of the second battery incurred after 13 years and assumed to cost 70% less than the first battery due to technological innovation driving down capital costs (DNV GL, 2016). The discounted cost analysis of this system suggests that the battery capital costs made up a third of the total costs to the consumer, with the capital costs of the solar PV system covering a similar share. The cost of importing electricity from the grid amounted to 8% of total expenses. Reduced electricity imports accounted for 89% of consumer revenues, with the remaining 11% from generation tariff payments.

To account for the removal of feed-in tariffs in 2019, Appendix I reports results for absolute and relative profitability by scenario in the absence of generation and export feed-in tariffs. The core results of this study, reported in Section 3.1.3, are unaffected from varying assumptions of feed-in tariffs since their use in calculating SNPV and NPV remains unvaried across different scenarios.

3.1.3 Comparison of NPV with System NPV

SNPV is found to always exceed NPV, meaning that estimation of consumer benefits with typical NPV calculations is likely to understate the profitability of investments in solar PV and EES. Figure 4 illustrates the percentage difference by which SNPV exceeds NPV. It therefore shows the magnitude by which NPV was underestimated compared to using an SNPV approach by way of assuming a static future electricity system. There are differences between SNPV and NPV ranging between 1–21% of the value of NPV, which is a substantial predictive error.

[4] The value of PV+EES should improve, relative to PV, as export tariffs are removed in April 2019 (Ofgem, 2018).

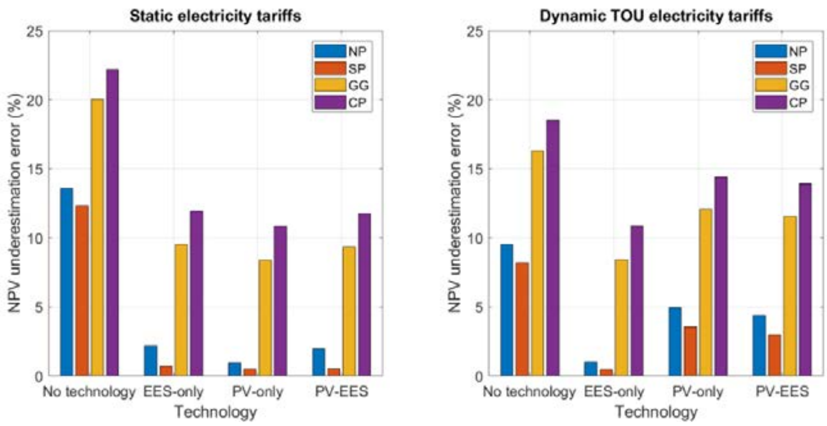

Figure 4. Percentage difference by which SNPV exceeds NPV. Positive values indicate percentage underestimation of NPV when not implicitly assuming a changing future electricity system between 2015 and 2040. The x-axis indicates the technology scenarios as: (i) No technology; (ii) EES-only; (iii) PV-only; (iv) PV+EES. The bars indicate future energy scenarios: NP=No Progression; GG=Gone Green; CP=Consumer Power; SP=Slow Progression. Note that the difference between SNPV and NPV in "No technology" is due to different electricity prices, which leads to different costs of importing electricity from the grid.

The difference between SNPV and NPV varies strongly between the examined electricity system scenarios. There is a substantial and consistently larger difference between SNPV and NPV in scenarios with increasing shares of renewables (Gone Green and Consumer Power) and involving dynamic tariffs. The former implies strong changes in electricity prices, whereas the latter means that consumer tariffs are more responsive to daily changes in consumer load or solar PV production, which amplifies the impact of system variables on SNPV, hence the difference with NPV.

Electricity tariff	Technology	Low renewables share	High renewables share
Static	None	13%	21%
	EES-only	2%	11%
	PV-only	1%	10%
	PV+EES	2%	11%
TOU	None	9%	18%
	EES-only	1%	10%
	PV-only	5%	13%
	PV+EES	13%	21%

Table 4. Percentage underestimation of SNPV relative to NPV. 'Low renewables' is the average of No Progression and Slow Progression scenarios, while 'High renewables' averages over Gone Green and Consumer Power.

Table 4 shows the percentage levels by which NPV is underestimated relative to SNPV in scenarios involving low and high renewable shares in total generation. Here, 'Low renewables' is the average of No Progression and Slow Progression scenarios, in which the share of renewables and level of electrification is low. 'High renewables' averages over Gone Green and Consumer Power, which are the scenarios with the highest renewable share, electrification, and retail electricity prices. It should be noted that the difference between SNPV and NPV in "No technology" is merely related to different electricity prices, which results in different net present values of the costs for importing electricity from the grid. This underestimation of SNPV ranges between 1% and 21%, with a larger gap showing in high-renewable scenarios.

3.1.4. Future electricity prices

In Section 2.1, the method for deriving future electricity prices and tariffs in a SNPV method are described. Figure 5 compares the consumer electricity prices between future scenarios of the SNPV method, i.e. high renewable scenarios Gone Green and Consumer Power, with low-renewable scenarios Slow- and No Progression, and with a fixed increase in electricity tariff (or the NPV method). These two future scenarios show the highest difference when comparing the results of SNPV and NPV. Both high-renewable scenarios show a dynamic behavior starting with higher prices in the beginning while flattening towards the end of the examined period. While the average electricity price over the technology's lifetime in a fixed-growth tariff may be close to the average prices in dynamic scenarios, the impact on discounted cash flow calculations is different when considering the variations in annual values. As dynamic scenarios overall show higher discounted electricity prices, they offer a more attractive investment in distributed technologies (PV and EES) for end users. The linear, fixed growth of electricity prices only exceeds dynamic prices towards the end of investment horizon with a relatively lower impact on net present values compared. Hence, even with the highest absolute prices in 2040, the fixed tariff does not capture the dynamics of price evolution accurately and as such NPV calculations based on this simple assumption differ from SNPV.

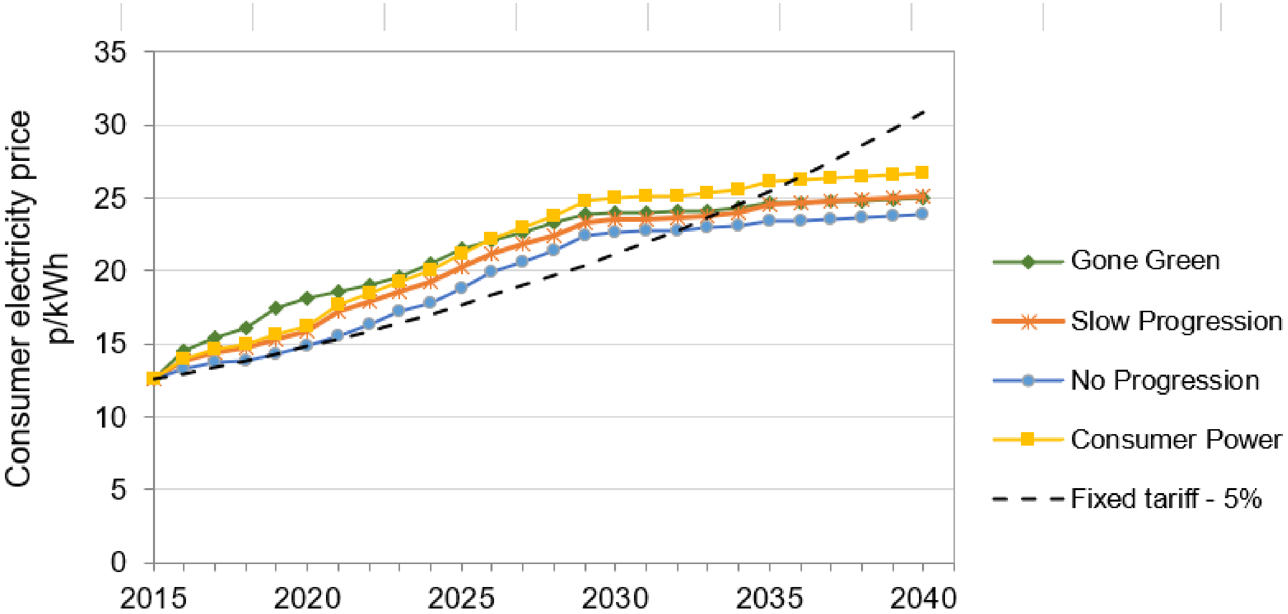

Figure 5. Comparison of scenario-driven electricity prices in the Gone Green, Slow Progression, No Progression, and Consumer Power scenarios used in SNPV calculations, versus a fixed tariff increasing 5% per year, which is used to calculate NPV.

It should be noted that the examined future scenarios here both represent a high share of variable renewable energy (VRE), which is expected to result in lower electricity prices due to the merit-order effect of wind and solar PV. However, this does not hold true, as (i) the electricity demand also increases under these scenarios due to higher electrification of the transport and the heating sector, (ii) a higher share of VRE increases the need for flexibility and backup generation endogenized in electricity prices, and (iii) a higher tax is imposed to end users to account for additional investment needs for integration of VRE (e.g., National Grid assumes a 60% increase and grid taxes due for subsidizing VRE in Consumer Power scenario). Hence, lower wholesale electricity prices in high-renewable scenarios does not directly translate to lower retail electricity prices for end users.

3.2 Sensitivity analysis

The robustness of our results is verified by calculating the change in SNPV for an investment in PV+EES subject to changes in several key parameters, in the spirit of Hoppmann *et al.* (2014). Here we consider the most likely evolution of the energy system by accounting for the cost of electricity averaged across the No Progression and Consumer Power scenarios. The sensitivity analysis, summarized in Figure 6, demonstrates that the results are robust to changes in key parameters and assumptions. The results of the sensitivity analysis for the examined parameters show that the impact of variations ranging between -100 % and +100 % in the input parameters changes the calculated SNPV in a range between - 20% and + 20%. In this sensitivity analysis, we change the value of input parameters in intervals of 33%, 66% and 100% relative to the base values, which was used in calculations so far. Considering a 100% higher and lower range offers a wide range for assessing the sensitivity of the results. The sensitivities show that absolute SNPV varies the most with the mean electricity tariff level, and the least with the negligible EES O&M costs[5]. Also, the results show SNPV will shrink by 7.4% if the nominal discount rate will be doubled to 10% year.

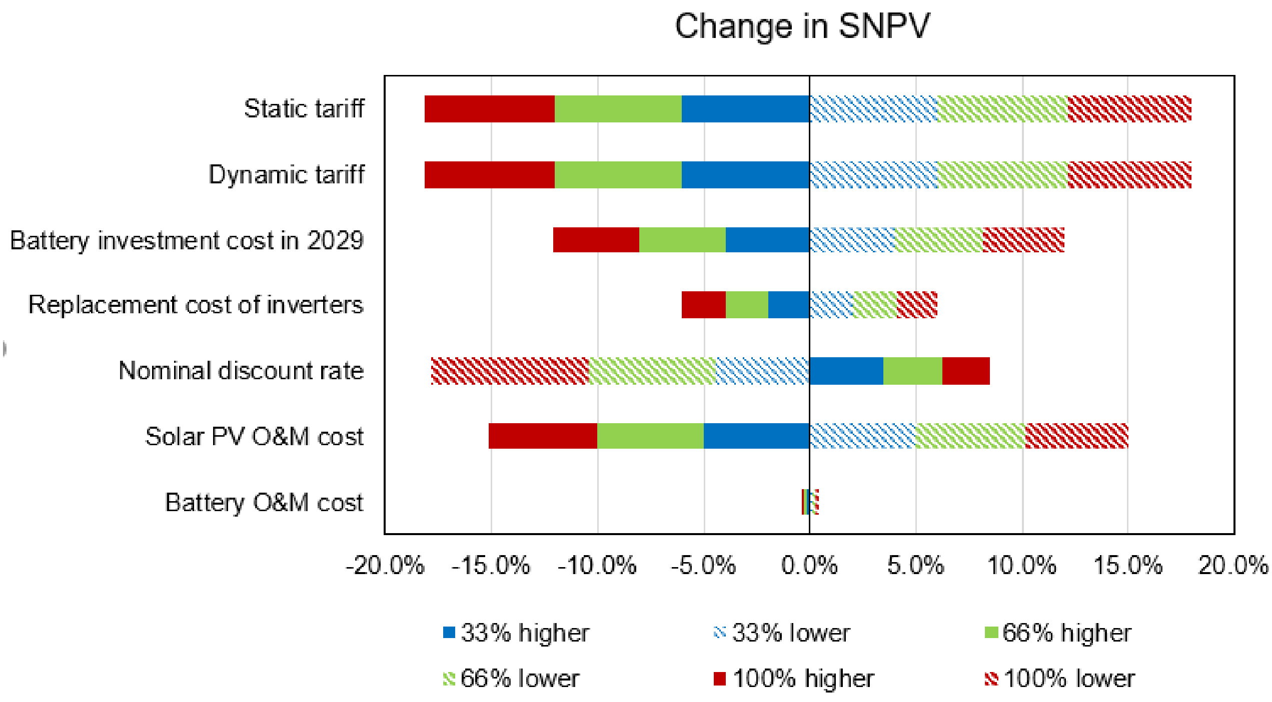

Figure 6. Sensitivity analysis. Percentage change in SNPV for each 2016£ invested in EES, in relation to a typical consumer's investment in PV+EES. Higher values show +33-100% change in Financial Case, while Low er values represent -33-100% change in Financial Case Variable. Except for the change in the static tariff, for which the base case applies, all other variable sensitivities assume the use of TOU tariffs. This approach is used as a result of the verified, higher impact of TOU tariffs on the consumer's savings using PV+EES. Solar PV O&M costs include the replacement costs of inverters and insurance. Battery O&M costs include the replacement costs and loss of capacity over time.

4 Discussion

Evaluations of the economic viability of a consumer's investment in new energy technologies using discounted net cash flow metrics such as NPV are highly dependent on assumptions of cash flow in the future, over the lifetime of the technology investment. Thus, these calculations are inaccurate if based on an implicit assumption that electricity price variations in the future: (1) are fixed and will not vary in the short- and long-run; and/or (2) are independent of the development of the electricity system over a long period. Studies typically assume a constant price growth rate and do not consider wider electricity system scenarios where the electricity price can be modelled as part of a certain evolution of the energy system. O'Shaughnessy et al. (2018) lists a number of studies that the electricity price is subject to a mean annual escalation or a flat rate when calculating cash flows. For example, Li et al. (2019) assumes an incremental increase of electricity prices from 0.2 to 0.4 $/kWh as an explicit assumption for estimating future cash flows.In order to overcome this limitation, we linked the calculation of NPV with a dynamic model of the power system that explicitly considers the time-dependent nature of electricity wholesale costs, depending on future evolution of the electricity system. We apply this method for calculating future electricity prices as one of the important input parameters for estimating NPV of distributed technologies such as PV and EES.

[5] We assume that the second battery's capital cost does not enter the balance sheet as O&M cost, but as a capital cost.

Here, we discuss that why a SNPV results in a much different understanding of the profitability of distributed technologies compared to typical NPV calculations. Related metrics of discounted cash flows, such as Return on Investment (ROI) and Internal Rate of Return (IRR), are also commonly used to analyze the financial attractiveness of an investment from similar perspectives. Examples using either metric are Padmanathan *et al.* (2017) and Formica and Pecht (2017), respectively. Like NPV, these metrics can be also improved by considering more realistic and dynamic assumptions of input values for future cash inflow/outflows.

4.1 Profitability of distributed energy technologies: the role of the underlying electricity system

Accounting for the future evolution of the energy system is an important factor when assessing the NPV of a consumer's energy investment. Neglecting changes in the wider system can lead to a risk of *underestimating* the profitability of technologies such as solar PV and battery storage, hence, discouraging investment in such technologies. This is especially the case as we move toward an electricity system that is substantially different from the current one. Widespread adoption of electric transport and electric heating will not only increase electricity demand and prices, it will impact the variations of them in short and long time . The integration of high shares of variable renewable energy and distributed energy generation is another transition that will impact electricity prices, by increasing the share of near-zero marginal cost generation in the system but also the need for flexibility, backup power plants, and grid integration and management costs. These evolutions in an energy transition pathway are complex to be represented by simple price assumptions as input to NPV calculations. Considering differences between NPV and the proposed SNPV the estimation error can increase by up to a meaningful 21% of the value of NPV, we find.

4.1.1. Differences between future scenarios

The results show different levels of profitability in investment in distributed energy technologies under different future energy scenarios. Table 6 depicts these differences by analyzing transitions in each scenario with respect to six key parameters: annual electricity demand, level of electrification, share of VRE, retail prices of electricity, installed capacity of storage, and economic growth. This will help to draw policy recommendations that can be applied beyond the focused energy system. The most promising scenarios for investment in solar PV and EES proved to be Gone Green and Consumer Power (see Section 3.1), the two scenarios with a high economic growth. Looking under the hood, these two scenarios also represent the highest level of VRE, electricity demand, and electrification among four examined scenarios. Electrification and higher demand for electricity increases electricity prices, as such, a better financial case for investing in distributed energy technologies versus buying electricity from the grid. Higher share of VRE in these two scenarios will slightly reduce wholesale electricity prices. However, consumers ultimately need to pay for higher retail electricity prices due to the integration of VRE. This is to compensate for subsidies paid to wind power installations and additional system costs such as grid extensions and flexibility needs for balancing VRE. Therefore, according to National Grid (2016) underlying assumptions, scenarios with higher shares of VRE introduce higher retail electricity prices to end users. This assumption is consistent with the observed trends in countries like Denmark and Germany, where the retail electricity prices have grown steadily as the share of VRE increases in the system.

Key parameters	Future Energy Scenario			
	No Progression	Low Progression	Gone Green	Consumer Power
Electricity demand	Low	Low	High	Moderate[a]
Electrification	Low	Moderate	High	Moderate[b]
Share of wind and solar PV	Low	Moderate	High	Relatively high
Retail electricity price	Low	Low	High	High
Installed capacity of storage and interconnector	Low	Low	Average	High
Economic growth	Low	Low	High	High

[a] The residential electricity demand grows but there is significant reduction in electricity demand in the industry due to fuel switching as gas prices are cheap.
[b] While the share of electric vehicles grows significantly, electric heating not that much due to low gas prices and use of micro CHP.

Table 6 Main differences between future energy scenarios, based on (National Grid, 2016).

Between Gone Green and Consumer Power, the former shows a higher profitability for investment in solar PV and EES. Because not only Gone Green has the highest share of VRE, it has lower levels of storage compared to Consumer Power. As such, the system needs more storage, and this is paid through electricity price signals that encourages investment in PV+EES to shift electricity use from peak hours. In other words, in systems that central electricity storage solutions are not enough to accommodate the needs of the system in high VRE scenarios, investment in PV combined with EES at the household level is more economically attractive. However, the retail tariffs such as TOU or more dynamic like hourly tariffs are needed to signal this need to the distributed generators and storage providers.

4.1.2. NPV or SNPV?

The energy system is expected to depart dramatically from the present determinants of demand and supply (National Grid, 2016), affecting the level and variations of electricity prices. Therefore, the fact that studies using NPV normally make an explicit assumption that retail tariffs will not vary considerably in the future (Hoppmann *et al.*, 2014) or vary at a fixed rate may misrepresent the profitability of energy technologies compared to an SNPV approach proposed here.

In the future, consumers could provide several technical services to the electricity system, including various capacity and ancillary services (Burger *et al.*, 2017), such as congestion relief. Providing these services could contribute dramatically toward system balancing and security when scheduled independently or via aggregators (He *et al.*, 2011). These services may have high value if scarce, but low value if abundant. Their abundance will depend on the level of VRE which, at scale, would imply that electricity supplies from distributed energy resources, such as solar PV or EES, could have greater private and system value. Considering how consumer technologies are affected by the differences between future energy scenarios is likely to become gradually more influential as more non-synchronous penetration come online. Accurately predicting the profitability of consumer technologies will increasingly depend on what other technologies are deployed, and how good short-run forecasting becomes, as these factors all affect the normal operation of electricity markets at various timeframes (including forward, day-ahead, intraday and balancing), to which distributed resources could sell valuable electricity system services (US Department of Energy, 2013). These factors can only be accounted for if SNPV is used over NPV.

Upon purchase of the solar PV or EES, governments should provide consumers with a clear understanding that the profitability of their technology is uncertain and strongly varies according to the potential future evolution of the energy system. The contribution of end-user energy technologies toward the electricity system via aggregation has been shown to be potentially meaningful toward reducing electricity prices and improving security of supply, whilst increasing the system's sustainability (Castagneto Gissey *et al.*, 2017), and this further emphasizes the importance of using a reliable underlying system model. Failing to ensure that consumers get an accurate estimation of the economic profitability of investment in new technologies may limit the deployment of technologies that could otherwise deliver important system-level benefits. This might also partially reverse some social benefits obtained with a feed-in tariff system. To encourage deployments, it is necessary to inform consumers about the potential benefits their technologies could deliver through increased private savings. This study showed it is possible to demonstrate a wider range of monetary benefits under various scenarios. It is not only necessary to incentivize the use of system-enhancing technology but it is also required to ensure that consumers understand the range of savings (and risk of loss) associated with their energy investments. This is particularly true as the grid develops and locational signals assume increased importance.

Due to the computational burden of using electricity system models, a potentially useful approach could be for governments to provide online scenario simulators for technology sellers to provide system-backed estimates of NPV, which could become a key marketing tool. For example, the US Department of Energy's System Advisor Model (SAM) (NREL, 2018) is a techno-economic computer model that calculates performance and financial metrics of renewable energy projects. While the project could be useful to address this purpose, it does not at present consider a spectrum of future energy scenarios. The estimation of any technology profitability indicators should ideally be supported by Government-provided software technology that can account for future energy scenarios.

4.2 Drawbacks and future work

Provision of appropriate software by governments for this purpose could improve transparency in relation to the calculation of final prices, which is an interesting topic for future work. The concept of SNPV relied on the assumption of retail electricity tariffs varying proportionately to the retail electricity price. Modelling this variation based on historical data of retail price mark-ups would improve the accuracy of our work. Yet this data is typically confidential and is difficult to find from reliable sources, which is why we did not undertake this option. As wholesale costs are the largest component of consumer bills with a share of over a third in Great Britain (Ofgem, 2017), we considered systemic impacts as those on wholesale prices.

We did not assume that EES could be used by consumers for economic purposes different from electricity bill management through arbitrage and excluded the potential future provision of balancing and ancillary services to the grid through aggregation, or management for non-economic purposes such as energy security. Wider consumer preferences can be important, but we considered financial benefit as the only determinant of adoption. Consumers could invest in storage for security reasons, environmental friendliness or simply because they are enthusiastic early adopters (House of Commons, 2007), and may make decisions irrationally (Sargent and Wallace, 1976), which are aspects we did not consider. We examined the capacity of solar PV and storage size within the threshold for benefiting from governmental subsides. Expanding this range to include different sensitivities to the size of storage and considering different weather years can improve the robustness of the results.

5 Conclusions and policy implications

National energy policies are increasingly centered on increasing the share of renewable energy in the energy system, for example by encouraging end users to invest in new distributed energy technologies such as solar PV and energy storage. The economic viability of such investments, which is one of the main parameters in the decision to deploy any such technologies, is typically assessed using Net Present Value (NPV) or other metrics of discounted net cash flows. Yet the input assumptions for calculating these measures do not commonly account for electricity price dynamics over the lifetime of the technology investment, which is a critical component in the determination of future cash flows. We propose a holistic, integrated framework to model different scenarios in the whole electricity system over multiple decades. We assessed the impact of accounting for these potential system evolutions on electricity price formation and NPV calculations in relation to end-user energy technology investments.

Taking Great Britain as an example, we showed that failure to account for the future evolution of the underlying electricity system can underestimate the profitability of solar PV and EES by up to a substantial 20%. We find that future electricity systems involving high levels of variable renewable energy and distributed generation imply the largest risks of under-estimation. Using electricity system-dependent net cash flow metrics is essential to ensure the accuracy of profitability estimates and may improve consumer confidence in new energy technologies, which could help spur investments that could help reduce the cost of future electricity systems

The potential financial benefits of end-user from investment in energy technologies depends on different parameters that are not easily captured in simple cash flow analyses. This includes electricity price dynamics caused by level and variations of electricity demand; the share of renewable energy in the system; the share of flexible generation, interconnector and storage in the system to balance variability issues; and the possibility for end users to sell ancillary services to the grid, among other things. Hence, a whole-system, model-based analysis of NPV can explore different energy scenarios and systematically estimate the impact of such scenarios on customer energy investments. This will provide the customer with additional information on system-wide evolutions that can offer more financial benefits when investing in distributed energy technologies. Hence, by providing end users with these insights, energy policy makers can reach a two-fold goal: (i) improve the confidence of end users in investment in green technologies that can ultimately help the system-level targets, (ii) attract the support of end users for certain energy transition pathways that has higher potential benefits for their energy investments; for example, scenarios with a high share of renewable energy.

To achieve this, policy makers need to provide the end user s with easy-to-understand and user-friendly tools and modelling interfaces. In this respect, the use of open data and open energy models play an important role (Pfenninger *et al.*, 2017; Ringkjøb *et al.*, 2018). Since the electricity models are rather complex with a large number of assumptions that are not easy for end users to investigate, efforts should be focused to develop open, user-friendly interfaces that the user can understand, navigate, and use to change some key input parameters in order to estimate the output. Presenting a better financial case to consumers together with reliable tools to assess this profitability would arguably encourage distributed energy investments that could contribute toward a more sustainable, lower-cost and secure power system.

5. Acknowledgments

This research was funded by the UK Engineering and Physical Research Council (EPSRC) through the Realising Energy Storage Technologies in Low-carbon Energy Systems (RESTLESS) project (EP/N001893/1); the Complex Built Environment Systems (CBES) Platform Grant (EP/P022405/1); and the Innovation Fund Denmark and International Institute for Applied Systems Analysis (IIASA) through the RE-INVEST project “Renewable Energy Investment Strategies – A two-dimensional interconnectivity approach”. The authors would also like to thank Professor Richard Green (Imperial College London) for useful comments and suggestions. We are also very grateful to the three anonymous reviewers for useful suggestions that improved the quality of the paper.

6. References

Arent, D.J., Wise, A. and Gelman, R., 2011. The status and prospects of renewable energy for combating global warming. *Energy Economics*, *33*(4), pp.584-593.

BEIS, 2016. Electricity generation costs.

Borenstein, S., 2017. Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives, and Rebates. Journal of the Association of Environmental and Resource Economists 4, S85-S122.

Bost, M., Hirschl, B., Aretz, A., 2011. Effekte von Eigenverbrauch und Netzparität bei der Photovoltaik: Studie im Auftrag von Greenpeace Energy. Berlin: Institut für ökologische Wirtschaftsforschung (IÖW).

Boxwell, M., 2017. Solar Electricity Handbook.

Braun, M., Büdenbender, K., Magnor, D., Jossen, A., 2009. Photovoltaic self-consumption in Germany: using lithium-ion storage to increase self-consumed photovoltaic energy, 24th European Photovoltaic Solar Energy Conference (PVSEC), Hamburg, Germany.

Burger, S., Chaves-Ávila, J.P., Batlle, C., Pérez-Arriaga, I.J., 2017. A review of the value of aggregators in electricity systems. Renewable and Sustainable Energy Reviews 77, 395-405.

Castagneto Gissey, G., Dodds, P.E., 2017. Policy options to encourage consumer investments in solar PV with energy storage. University College London.

Castagneto Gissey, G., Subkhankulova, D., Dodds, P.E., Barrett, M., 2019. Value of energy storage aggregation to the electricity system. Energy Policy 128, 685-696.

CCC, 2013. Energy bills supporting data. London, UK: Committee on Climate Change. Available at: https://www.theccc.org.uk/wp-content/.../12/Energy-Bills-supporting-data-Copy.xls.

Chesser, M., Hanly, J., Cassells, D., Apergis, N., 2018. The positive feedback cycle in the electricity market: Residential solar PV adoption, electricity demand and prices. Energy policy 122, 36-44.

Clark, L.E., Edmonds, J.A., Krey, V., Richels, R.G., Rose, S., Tavoni, M., 2009. International Climate Policy Architectures: Overview of the EMF 22 International Scenarios. Energy Economics 31 (2), S64–S81.

Clastres, C., Pham, T.H., Wurtz, F., Bacha, S., 2010. Ancillary services and optimal household energy management with photovoltaic production. Energy 35, 55-64.

Colmenar-Santos, A., Campíñez-Romero, S., Pérez-Molina, C., Castro-Gil, M., 2012. Profitability analysis of grid-connected photovoltaic facilities for household electricity self-sufficiency. Energy Policy 51, 749-764.

Comello, S., Reichelstein, S., Sahoo, A., 2018. The road ahead for solar PV power. Renewable and Sustainable Energy Reviews 92, 744-756.

Cucchiella, F., D'Adamo, I., Gastaldi, M., 2016. Photovoltaic energy systems with battery storage for residential areas: an economic analysis. Journal of Cleaner Production 131, 460-474.

DECC, 2016. Solar Photovoltaics Deployment. Change, D.o.E.a.C. London, UK. Available at: https://www.gov.uk/government/statistics/solar-photovoltaics-deployment.

Department of Energy and Climate Change, 2013. UK Solar PV Strategy Roadmap to a Brighter Future.

Dietrich, A., Weber, C., 2018. What drives profitability of grid-connected residential PV storage systems? A closer look with focus on Germany. Energy Economics 74, 399-416.

DNV GL, 2016. E-Storage: Shifting from Cost to Value.

EDF Energy, 2016. Grid Connection Costs.

Energy Saving Trust, 2011. A buyer's guide to solar electricity panels.

Formica, T., Pecht, M., 2017. Return on investment analysis and simulation of a 9.12 kilowatt (kW) solar photovoltaic system. Solar Energy 144, 629-634.

Gillingham, K., Newell, R.G., Pizer, W.A., 2008. Modeling endogenous technological change for climate policy analysis. Energy Economics 30 (6), 2734–2753. November 2008

He, X., Delarue, E., D'haeseleer, W., Glachant, J.-M., 2011. A novel business model for aggregating the values of electricity storage. Energy Policy 39, 1575-1585.

Hoppmann, J., Volland, J., Schmidt, T.S., Hoffmann, V.H., 2014. The economic viability of battery storage for residential solar photovoltaic systems–A review and a simulation model. Renewable and Sustainable Energy Reviews 39, 1101-1118.

House of Commons, 2007. Local energy: Turning consumers into producers.

Joskow, P., 2011. Comparing the costs of intermittent and dispatchable electricity generating technologies. The American Economic Review 101, 238-241.

Kaldellis, J., Zafirakis, D., Kaldelli, E., Kavadias, K., 2009. Cost benefit analysis of a photovoltaic-energy storage electrification solution for remote islands. Renewable energy 34, 1299-1311.

Kyle, P., Clarke, L., Pugh, G., Wise, M., Calvin, K., Edmonds, J., Kim, S., 2009. The value of advanced technology in meeting 2050 greenhouse gas emissions targets in the United States. Energy Economics 31 (2009), S254–S267

National Grid, 2016. Future Energy Scenarios.

National Renewable Energy Laboratory, 2016. Photovoltaic Degradation Rates: An Analytical Review

NREL, 2011. The impact of different economic performance metrics on the perceived value of solar photovoltaics. Contract 303, 275-3000.

NREL, 2018. System Advisor Model (SAM) General Description (Version 2017.9.5).

Ofgem, 2013. Decision note on new typical domestic consumption values. Markets, O.o.G.a.E. London, UK. Available at: https://www.ofgem.gov.uk/ofgem-publications/86691/tdcvdecisionletterfinal2-pdf.

Ofgem, 2016. FiT tariff rates. Markets, O.o.G.a.E. London, UK. Available at: https://www.ofgem.gov.uk/environmental-programmes/fit/fit-tariff-rates.

Ofgem, 2017. Infographic: Bills, prices and profits. Markets, O.o.G.a.E. London, UK. Available at: https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits.

Ofgem, 2018. Feed-in Tariffs FAQ: Announcement on Prospective Scheme Closure

ONS, 2015. Quarterly energy prices. Statistics, O.f.N. London, UK.

ONS, 2016. Inflation and Price Indices. Statistics, O.f.N. London, UK. Available at: https://www.ons.gov.uk/economy/inflationandpriceindices.

O'Shaughnessy, E., Cutler, D., Ardani, K., Margolis, R., 2018a. Solar plus: A review of the end-user economics of solar PV integration with storage and load control in residential buildings. Applied energy 228, 2165-2175.

O'Shaughnessy, E., Cutler, D., Ardani, K., Margolis, R., 2018b. Solar plus: Optimization of distributed solar PV through battery storage and dispatchable load in residential buildings. Applied Energy 213, 11-21.

Padmanathan, K., Govindarajan, U., K Ramachandaramurthy, V., Selvi, T.S.O., 2017. Multiple criteria decision making (MCDM) based economic analysis of solar PV system with respect to performance investigation for Indian market. Sustainability 9, 820.

Pfenninger, S., Staffell, I., 2016. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, 1251-1265.

REPN, 2011. Renewables 2011 Global Status Report. Renewable Energy Policy Network for the 21st Century.

Ribeiro, P.F., Johnson, B.K., Crow, M.L., Arsoy, A., Liu, Y., 2001. Energy storage systems for advanced power applications. Proceedings of the IEEE 89, 1744-1756.

Rodrigues, S., Torabikalaki, R., Faria, F., Cafôfo, N., Chen, X., Ivaki, A.R., Mata-Lima, H., Morgado-Dias, F., 2016. Economic feasibility analysis of small scale PV systems in different countries. Solar Energy 131, 81-95.

Sargent, T.J., Wallace, N., 1976. Rational expectations and the theory of economic policy. Journal of Monetary Economics 2, 169-183.

SolarTherm UK, 2016. Tesla battery storage costs.

Tesla, 2016. Tesla Powerwall 1.

The Eco Experts, 2016. Average cost of solar inverters.

UCL, 2014. UK TIMES Model Overview. Available at: http://www.ucl.ac.uk/energy-models/models/uktm-ucl/uktm-documentation-overview.

UKERC, 2018. A distributed energy future for the UK: An essay collection. Available at: http://www.ukerc.ac.uk/network/network-news/challenges-and-opportunities-of-a-decentralised-energy-future.html.

US Department of Energy, 2013. Grid Energy Storage Report. Energy, U.D.o. USA.

Williams, J.H., DeBenedictis, A., Ghanadan, R., Mahone, A., Moore, J., Morrow, W.R., Price, S., Torn, M.S., 2012. The technology path to deep greenhouse gas emissions cuts by 2050: the pivotal role of electricity. science 335, 53-59.

New references:

Benis, K., Turan, I., Reinhart, C., Ferrão, P. (2018). Putting rooftops to use – A Cost-Benefit Analysis of food production vs. energy generation under Mediterranean climates. *Cities*, *78*, 166–179. https://doi.org/10.1016/j.cities.2018.02.011

Boampong, R., Brown, D. P. (2020). On the benefits of behind-the-meter rooftop solar and energy storage: The importance of retail rate design. *Energy Economics*, *86*, 104682. https://doi.org/10.1016/j.eneco.2020.104682

Li, H. X., Horan, P., Luther, M. B., Ahmed, T. M. F. (2019). Informed decision making of battery storage for solar-PV homes using smart meter data. *Energy and Buildings*, *198*, 491–502. https://doi.org/10.1016/j.enbuild.2019.06.036

Lyon, T. P. (2016). Impacts of Renewable Portfolio Standards. *SSRN Electronic Journal*. https://doi.org/10.2139/ssrn.2719354

Martin, N., Rice, J. (2018). Solar Feed-In Tariffs: Examining fair and reasonable retail rates using cost avoidance estimates. *Energy Policy*, *112*, 19–28. https://doi.org/10.1016/j.enpol.2017.09.050

Muhammad-Sukki, F., Ramirez-Iniguez, R., Abu-Bakar, S. H., McMeekin, S. G., Stewart, B. G. (2011). An evaluation of the installation of solar photovoltaic in residential houses in Malaysia: Past, present, and future. *Energy Policy*, *39*(12), 7975–7987. https://doi.org/10.1016/j.enpol.2011.09.052

O'Shaughnessy, E., Cutler, D., Ardani, K., Margolis, R. (2018). Solar plus: A review of the end-user economics of solar PV integration with storage and load control in residential buildings. In *Applied Energy* (Vol. 228, pp. 2165–2175). Elsevier Ltd. https://doi.org/10.1016/j.apenergy.2018.07.048

Pfenninger, S., Decarolis, J., Hirth, L., Quoilin, S., Sta, I. (2017). *The importance of open data and software : Is energy research lagging behind ? 101*(July 2016), 211–215. https://doi.org/10.1016/j.enpol.2016.11.046

Poullikkas, A. (2009). Parametric cost-benefit analysis for the installation of photovoltaic parks in the island of Cyprus. *Energy Policy*, *37*(9), 3673–3680. https://doi.org/10.1016/j.enpol.2009.04.037

Ramadhan, M., Naseeb, A. (2011). The cost benefit analysis of implementing photovoltaic solar system in the state of Kuwait. *Renewable Energy*, *36*(4), 1272–1276. https://doi.org/10.1016/j.renene.2010.10.004

Ringkjøb, H., Haugan, P. M., Solbrekke, I. M., Zürich, E. T. H., Pfenninger, S. (2018). A review of modelling tools for energy and electricity systems with large shares of variable renewables. *Renewable and Sustainable Energy Reviews*, *96*(July), 440–459. https://doi.org/10.1016/j.rser.2018.08.002

Ross, M. T. (2018). The future of the electricity industry: Implications of trends and taxes. *Energy Economics*, *73*, 393–409. https://doi.org/10.1016/j.eneco.2018.03.022

Schwarz, H., Schermeyer, H., Bertsch, V., Fichtner, W. (2018). Self-consumption through power-to-heat and storage for enhanced PV integration in decentralised energy systems. *Solar Energy*, *163*, 150–161. https://doi.org/10.1016/j.solener.2018.01.076

Varghese, S., Sioshansi, R. (2020). The price is right? How pricing and incentive mechanisms in California incentivize building distributed hybrid solar and energy-storage systems. *Energy Policy*, *138*, 111242. https://doi.org/10.1016/j.enpol.2020.111242

Zakeri, B., Syri, S. (2015). Electrical energy storage systems: A comparative life cycle cost analysis. *Renewable and Sustainable Energy Reviews*, *42*. https://doi.org/10.1016/j.rser.2014.10.011