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Solar PV where the sun doesn't shine: Estimating the economic impacts of support schemes for residential PV with detailed net demand profiling

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ABSTRACT

Countries with low irradiation and solar PV adoption rates are increasingly considering policy support for solar PV, although consumer electricity demand and solar generation profiles are often mismatched. This paper presents a methodology for policymakers in such conditions to examine more precisely the financial performance of residential solar PV from the consumer perspective as part of an ex-ante policy assessment. We model a range of prospective policy scenarios and compare policy mechanisms that compensate homeowners for generation, those that reduce their upfront costs, and those that assist with financing, using Ireland as a case study. The results confirm the intuitive notion that more generous financial remuneration schemes provide quicker payback; however we observe that in low irradiance regions there is little difference between upfront grants and feed-in-tariffs to accelerate payback timeframes. We also show the importance of retail tariff structure in consumer payback for solar PV systems, with one-part tariffs generating shorter paybacks than two-part tariff structures, although the latter is more likely to secure revenue for electricity infrastructure investment. Drawing from this analysis, the paper proposes some options for the design of policy supports and tariff structures to deliver a sustainable residential renewable electricity system in low-irradiance regions.

1. Introduction

Solar photovoltaic (PV) technology has experienced a dramatic reduction in installed costs in recent years, falling more than 80% since 2008 (IRENA, 2015). As the technology becomes more competitive with conventional generation sources, deployment has increased sharply, reaching 177 GW total installed capacity worldwide in 2014 (REN21, 2015). The majority of deployment thus far has naturally been concentrated in locations with some combination of a strong solar resource or sufficiently generous policy supports, which in some cases have created windfall benefits for asset owners at high public cost, ultimately leading to unstable, boom-and-bust market dynamics (De Boeck et al., 2016). As PV costs continue to fall, policymakers in countries with lower solar irradiation are also beginning to consider whether solar PV might be a viable renewable energy resource and worthy of policy support. In the development of such policies, these late-adopters have significant opportunity to avoid the mistakes of others in the design of policy support mechanisms and pricing through learning from other countries' experiences. Careful analysis is thus required to assess whether solar PV is an appropriate technology justifying policy support in such countries.

In carrying out ex-ante solar PV policy assessment, policymakers should consider a range of key factors, including the system value of increasing the share of solar PV on the electricity system, the current and future economics of solar PV for different customers—residential, commercial, and utility-scale—and the environmental and other impacts of increased solar PV electricity generation. Of these, this paper focusses on the assessment of consumer economics of residential solar PV using Ireland as a case study, and examines the effect of remuneration schemes, tariff structures, and financing mechanisms on financial performance. It follows a related paper on the system value of utility-sale solar PV (Ryan et al., 2016).

Many existing papers offer comparative analysis of financial performance under various support mechanisms between different countries with varying costs, irradiance profiles, and other market conditions (see for example: Couture and Gagnon, 2010; Sarasa-Maestro et al., 2016; Campoccia et al., 2014; Dusonchet and Telaretti, 2015; de Boeck et al., 2016; Lacchini and Ruther, 2015). As of 2015, feed-in tariffs (FiTs) were in place in 108 national or state

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jurisdictions around world (REN21, 2015). While some research shows that feed-in tariffs "consistently delivered new renewable energy (RE) supply more effectively, and at lower cost, than alternative policy mechanisms" (Couture and Gagnon, 2010), others offer more cautionary comments regarding the dangers of overly generous FiTs that are costly to governments (and ultimately, to ratepayers), and can yield windfall profits for investors (Sarasa-Maestro et al., 2013). Lacchini and Ruther (2015) find, on the other hand, that policies should be focussed on reducing upfront investment costs rather than providing generation-based remuneration. Given the lack of universal agreement on the type of policy most effective and efficient for solar PV, it is clear that optimal design should be informed by the solar resource and other market characteristics in the individual country.

A consideration for policy makers in new solar PV jurisdictions, and also the focus of a growing academic literature, is the detrimental impact of high shares of distributed solar PV on supplier revenues. In many countries, the costs of distribution, transmission and generation of electricity are recovered through retail tariffs levied on a volumetric basis (Darghouth et al., 2015). In such cases, solar PV customers who demand less electricity from the grid also avoid paying for electricity system costs. With net metering policies, under which PV customers are paid the retail rate for the total amount of electricity they generate, this effect is particularly acute, and constitutes an implicit subsidy by which customers are effectively paid for distribution, transmission and generation services that they do not provide (Kirsch and Morey, 2015).[1] In a world with higher shares of distributed renewable generation, another form of tariff will likely be needed to recover fixed costs of grid services (Sioshansi, 2016). One option is a two-part tariff that includes a fixed charge for grid services and a volumetric electricity charge (Darghouth et al., 2011). In any case, the design of the tariff has a strong impact on the financial performance of PV systems and therefore both the current and potential future structure of retail tariffs should be considered by policymakers in assessing the economics of solar PV policies.

The cost of financing also exerts a strong influence on the financial feasibility of solar PV projects (Ondraczek et al., 2015; Tao and Finenko, 2016). Intuitively, it follows that localities that offer financial incentives experience increased rates of PV deployment, as confirmed by Jacobsson and Lauber (2006), Sarzynski et al. (2012), and Crago and Chernyakhovskiy (2017). Notably, the financing conditions and hence options for residential consumers are different than those applicable to commercial investors. Households may have significant savings and prefer to pay for a PV system in cash, especially when deposit interest rates are low. Others may be more likely to use debt finance, in which case lending rates will determine the cost of servicing that debt. It is critical also to recognise that households use different decision-making criteria for capital budgeting decisions compared with commercial entities, and financial performance must be evaluated accordingly. Faiers and Neame (2006) find that payback period (PBP) is the metric that holds the greatest sway over homeowners' decision-making process when considering an investment in rooftop PV. Lee et al. (2016) also use payback period, citing Rai and McAndrews (2012), who find that households require a payback period of seven to ten years in order to proceed with rooftop PV investment. Scarpa and Willis (2010) find an even shorter required timeframe of between three and five years, though a ten year maximum is perhaps more appropriate in the context of an immature market such as the one examined herein.

Many researchers have provided a critical contribution with regard to the retrospective assessment of customer economics in a range of policy environments. Necessarily, however, much of the existing research and ex-post policy analysis examines conditions in countries where the combination of strong solar resources and supportive policies led to early adoption. We believe that a more targeted approach is appropriate for the purposes of identifying, ex-ante, the effect of these policies on prospective PV uptake in the residential sector. Economists have pointed out that electricity is a heterogeneous product in time, space, and lead-time dimensions (Hirth et al., 2016; Borenstein, 2012; Joskow, 2011). Therefore, since the value of electricity and the amount of solar PV generation changes over time, biases occur when financial performance is based on average values, as is often the case in the existing solar policy literature. This may be particularly important in jurisdictions where there is a mismatch between the timing of electricity demand and solar generation, such as in countries in the northern hemisphere with low solar irradiation and large variations between the length of day in winter and summer.

While we find no commonly-used scale or ranking for "low irradiance" in the literature, Ondrececk et al. (2015), using data compiled by Breyer and Gerlach (2013), show that the lowest solar resource of any region in the world is found in Northern European countries with maximum irradiance of 1000 kWh/kWp per annum. These countries include the Netherlands, Belgium, Denmark, Lithuania, Latvia, Ireland, UK, Estonia, Sweden, Finland, and Iceland (JRC, 2017). While some literature explores the deployment of PV in these countries (see: Huijben and Verbong, 2013; Leloux et al., 2012; Martins, 2017) – particularly in the UK (e.g. Colantuono et al., 2014; Balta-Ozkan et al., 2015), which has offered considerable incentive programmes – none, to our knowledge, focus specifically on the low-irradiance characteristics of these markets, such as the differences in load profile, seasonal peak demand, and effect on consumer financial performance.

In this paper we present a methodology for assessment of the financial performance of a rooftop PV installation from the system owner's perspective with detailed profiling using hourly generation and demand patterns for the entire system lifetime. Given the sensitivity of residential solar profitability to self-consumption rates, our detailed analysis offers a more accurate estimate of self-consumption and net export than is presented in much of the existing literature, which tends to feature broad assumptions about net output and self-consumption proportions. Here, we explore potential profitability with greater precision by focussing on the example of Ireland, which features one market with relatively consistent costs, irradiance, and consumer profiles in a low solar irradiance location without a solar PV support mechanism. This approach improves upon previous papers' findings, which may be of diminished utility due to the presence of heterogeneous market conditions. Finally, we examine the influence of the significant determinant factors discussed above on residential solar PV economics, including remuneration policy supports, different household financing options and the electricity tariff structure using some traditional discounted cash flow metrics (net present value and internal rate of return), but with a particular focus on payback period.

Section 2 of the paper provides additional background on the factors affecting financial performance of residential PV, as well as the renewable energy policy and context in Ireland. Section 3 details the data and methodology employed; Section 4 presents overall findings and discussion; and Section 5 concludes with observations on policy implications arising from our results.

2. Background – Solar PV in Ireland

We examine Ireland as a case study for late adoption of solar PV. Ireland has a relatively low solar resource and only a negligible amount of residential PV currently exists; its government is in the process of a multi-stage consultation on prospective renewable energy support schemes (SEAI, 2013; DCENR, 2015a). In Ireland, renewable electricity has mainly been generated by onshore wind, supported by a feed-in tariff since 2006 (DCENR, 2013). By end of 2015, 21.1% of electricity

[1] Conversely, distributed generation may also provide some ancillary services for which asset owners are not adequately remunerated.

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