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Supporting the externality of intermittency in policies for renewable energy

Derek W. Bunn [a,*], José I. Muñoz [b]

[a] London Business School, Sussex Place, Regent's Park, London NW1 5SA, UK
[b] Universidad de Castilla – La Mancha, E.T.S. de Ingenieros Industriales, 13071 Ciudad Real, Spain

HIGHLIGHTS

- Progressively replacing coal by offshore wind may require increasing subsidies.
- Risk-averse investors seek higher financial hurdles with more intermittent technologies.
- The externality of providing extra reserves should be bundled with the renewable subsidies.
- Using capital grants rather than green certificates leads to lower costs.

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ABSTRACT

We analyse the joint problem of supporting renewables and resource adequacy in a liberalised electricity market and present a detailed model-based comparison of two alternative policies. We undertake this in the context of the British market. We show how, ceteris paribus, the progressive replacement of coal with wind imposes extra costs of reserve and evaluate alternative way to meet this, whether through capacity payments funded by customers, or a reliability requirement on wind generators with capital cost or energy feed-in subsidies. We consider the reality of market concentration and the extent to which pragmatic regulation could allow prices to rise above marginal cost to reduce the extent of direct subsidies and complex market designs. We also evaluate the implied cost of carbon reduction in a progressive replacement of coal with wind, when the security is maintained by extra peaking gas. We find that support through capital allowances rather than the energy market is more efficient.

1. Introduction

The process of replacing conventional fossil fuel power generation with intermittent renewable energy facilities imposes substantial externality costs on the electricity system. Wind generation in particular is not a simple plug-in replacement for coal and gas power stations. The re-configuration of the transmission network, the need for extra flexible generation, the holding of more operating reserve, the re-design of balancing products to accommodate more active real time markets (e.g. 15 min contracts), as well as system stability issues (e.g. reactive power) and greater inter-regional connectivity, have all become necessary extra expenses attributable to the introduction of large amounts of wind power. In a liberalised market setting, motivating the introduction of new renewable technologies is therefore not only about how the new facilities themselves should be subsidised (e.g. through feed-in-tariffs, green certificates or capital allowances) but also the recovery of the associated externalities. As a consequence, in several countries, moving towards a low carbon power sector has entailed radical changes to the way the power markets function and the degree of government interventions. The Electricity Market Reform processes in Britain (DECC, 2011) and the Energiewende in Germany (BMWI, 2014) are well-cited examples of this process of institutional re-engagement in fully liberalised markets, but similar changes are prominent throughout Europe and elsewhere.

The more widespread introduction of capacity markets to secure resource adequacy is clearly one of these consequences. Whether and how to introduce extra payments to generators for available capacity in addition to their revenues from the wholesale market for energy produced, have been open questions in electricity markets ever since their inception (Schweppe et al., 1988) and these have apparently become more urgent with the

* Corresponding author.
E-mail addresses: dbunn@london.edu (D.W. Bunn), joseignacio.munoz@uclm.es (J.I. Muñoz).

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introduction of renewable generation (European Commission, 2015). Intermittent renewables such as wind and solar require greater reserves than the fossil fuel facilities which they replace, and, as such, the extra resource adequacy cost becomes a significant one of their externalities. Furthermore, in projecting forward the support costs for renewable energy, whilst the direct technology subsidies might be expected to degress according to learning, lower capital costs and improved efficiencies (Gross and Heptonstall, 2010; CCC 2011), some of the externalities may not, and indeed the extra capacity needed to maintain resource adequacy, for example, may be an increasing function of the amount of wind penetration in the capacity mix (Bunn and Yusupov, 2015).

Economic efficiency prescribes that externality costs should be apportioned to their causes, and within power markets, this principle has been widely applied to carbon, pollution and network charges. With this in mind, in this research, we examine the joint implications and costs of policies for progressively replacing fossil fuels with an intermittent technology, wind, whilst maintaining resource adequacy to a constant reliability standard. Our focus is not to fully cost all the externalities of wind, but to focus in detail on one element, its reserve implications, and in particular to investigate if, by analyzing the support policies jointly, more efficient solutions can be achieved. If intervention policies for a low carbon transition are intended to move towards technological neutrality and balance externalities (as in Britain, DECC 2014, and more generally in the EU through "state aid" restrictions, European Commission (2014)), then it is evidently efficient to price the externality alongside the particular technology support. *Ceteris paribus*, a low carbon technology with less negative externalities should be preferred, if a choice is being made (e.g. within an auction) or incentives being set (e.g. through the allocation of green certificates). When the cost of an externality, such as extra reserve, is socialized, e.g. as part of a general capacity payments system with the cost spread across consumers, this allocative efficiency is lost.

To address this in a somewhat stylised setting, we compare the socialized externality cost of general reserve with one where the intermittent generators that receive a subsidy must also invest pro rata in the extra reserve costs which they incur. Evidently, they may require a higher subsidy as a consequence, but in our analysis, the overall efficiency is improved and costs reduced. We address some of the obvious concerns and counter-arguments to this capacity obligation later, but for the moment we note that such a requirement is comparable to the capacity obligations that are placed, in some markets, on utilities to forward contract a sufficient amount of energy (e.g. as proposed in France, RTE (2014)) and indeed, in terms of pricing a social externality, it would be analogous to the directive that fossil generators in the EU must cover their production with carbon allowances. Thus, we undertake an analysis whereby the cost of intermittency is placed as an obligation upon the intermittent producers but we retain the market context. This is distinct from research that has looked at the synergies of integrated production and storage systems for intermittent producers, or other ways of managing their real-time balancing market risks.

We consider the two main classes of support for renewable investment, namely through capital allowances (e.g. grants, capacity payments and/or tax benefits) or through energy price subsidies (e.g. green certificates or feed-in-tariffs). Although most renewable energy technologies are capital intensive with almost zero marginal production costs, supporting their development through energy rather than capital subsidies has been, perhaps surprisingly, as common as through capital grants (KPMG, 2011; Poullikkas et al., 2012). This is presumably because of the attraction of linking the support mechanisms more closely to the market prices, through which it is easier to pass the costs on to consumers, than through the more politically sensitive fiscal methods. Furthermore, fiscal support is often perceived as being unstable (Pablo-Romero et al., 2013). Nevertheless, the capital and fiscal incentives that followed the US Energy Policy Act (United States Congress, 1992) provided an effective motivation, as indeed did the various energy subsidies, via Feed-in-Tariffs and green certificate schemes, in Europe following the Renewables Directive (Eurpean Commission, 2001). Since both fiscal benefits and energy price subsidies have been successful in various parts of the world (an indeed co-exist across the EU within the State-Aid rulings), we consider in this research, simple capital grants and green certificates as generic examples of the two distinctly different support policies. We do not address the practical details of tax incentives, or the various mechanisms for green certificate schemes, contracts-for-differences and feed-in tariffs. Furthermore we do not address the speculative question of whether the market for carbon allowances will re-emerge with sufficient tightness to create the high carbon prices that would dilute the need for other low-carbon subsidies. We keep carbon prices at their low 2012 average level and this allows a clearer focus upon the subsidy mechanisms.

One key element that introduces subtlety into our analysis is that we recognise that wholesale electricity prices emerge from imperfect markets with generation being concentrated to some extent into a few owners, and prices thereby clearing above short-run marginal cost. With an allowance for market power and higher prices, evidently the need for capacity payments is reduced. Furthermore, given our setting in which the wind generators are required also to be investors in peaking capacity, this may also contribute to some market power effects. Whilst it is clearly a delicate issue to design policy support around the presumption of imperfect competition, not least because it requires a view on the market ownership structure and conduct going forward, such a pragmatic view is now becoming widespread in policy analysis. Electricity wholesale market models, as contracted by policy makers, generally incorporate mark-ups above marginal cost (Redpoint, 2007; Pöyry 2009; Baringa, 2013) and indeed the rationale for energy-only markets without any capacity payments has to make the pragmatic assumption of market power. We consider a realistic, moderately concentrated market structure for this analysis and use a well-established computational learning approach to derive the market prices, following Bower and Bunn (2000).

Our analysis uses Britain as a case study to develop generalisable model-based insights. We calibrate a model to the perspective of 2012, and simulate what the effects would be of progressively replacing coal with offshore wind in the capacity mix. This is a very specific setting, but it does provide some surprising indications. The model simulates probabilistically the market prices, loss-of-load expectations (LOLE) and the financial risks of investment in new generation. It also evaluates the cost of maintaining the LOLE at its 2012 level as wind replaces coal. The extra required investment needed to maintain a constant LOLE is provided through gas turbine generation to compensate for wind intermittency. We recognised that now and in the future, reserves can be maintained through a variety of technologies, demand side management and greater interconnections, but we are not seeking to forecast these developments; rather we wish to explore alternative support schemes in a realistic but controlled market simulation. The new wind capacity, and the extra gas turbines, need to be viable investments and require support beyond that provided by the energy market, even with the exercise of some moderate market power. In 2012, the British generating market was considered to be quite competitive, and in our data the HHI index for market concentration on installed capacity was under 1100, with average market prices appearing to be about 15% above short-run marginal costs. The reserve margin was comfortable with the LOLE being less than 1 h per year, compared to the