Energy Policy 110 (2017) 386–393

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Some problems in storing renewable energy[☆]

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ARTICLE INFO

Keywords:
Energy storage
Renewable energy

ABSTRACT

Difficulties involved in some commonly advocated options for the storage of renewable electricity are discussed. As is generally recognised the most promising strategies involve biomass and pumped hydro storage, but these involve drawbacks that appear to be major limitations on the achievement of 100% renewable supply systems. Neglected aspects of the solar thermal storage solution are detailed, indicating that it is not likely to be able to make a significant contribution. Batteries, vehicle-to-grid, biomass and hydrogen based solutions also appear to have major drawbacks. Although other options not examined here might alter the outlook, the general impression arrived at is that the probability of achieving satisfactory storage provision enabling 100% renewable power supply are not promising. Provision of total energy supply from renewable sources would probably multiply the task by an order of magnitude.

1. Introduction

Claims that renewable energy can meet most or all power demand involve large scale dependence on some form of storage to deal with periods in which little or no input from renewable energy sources is available. There is widespread confidence, especially in popular media, that before long storage technologies enabling 100%renewable energy supply will be achievable at convenient cost. However there has been relatively little analysis of the difficulties involved in enabling solutions on the very large scale that the 100% goal would involve. The following discussion is not a comprehensive review but attempts to point to some problems in a number of the most commonly assumed strategies.

The issue is of major significance for policy choices. If technically feasible and affordable storage solutions are not found renewable systems cannot approach 100% of supply and there will have to be considerable dependence on nuclear and/or carbon sequestration strategies.

The assumptions used here are based on the Australian situation, where renewable resources are likely to be among the best in the inhabited world. Recent simulations of 100% renewable electricity supply have for the first time indicated the magnitude of the Australian storage task. The following discussion mostly uses the findings of the study of this issue carried out by Lenzen et al. (2016)

2. Intermittency affects both storage rate and storage volume

Before considering particular options it is appropriate to note that the general storage task involves two factors. The pattern of input by wind farms to a national grid, such as that given for Germany by the Union for the Co-ordination of Transmission of Electricity, (2004) shows that power generated constantly varies markedly. Often there are extreme but short lived peaks and at times there is negligible output. This means that if power surplus to requirements is to be stored this would have to be done at a high rate for many quite short periods. If for instance storage was to be carried out by pumped hydro then there would have to be a very large amount of pumping capacity to store a lot of water during those brief periods when power was available. In the UCTE plot input is above 50% of peak capacity for only about one-tenth of the time, and to store all surplus wind energy would require pumping capacity capable of using half the total wind system peak output, or around three times the average wind output.

It would be too costly to have sufficient pumping capacity to harvest all output including the infrequent peaks so some of it would be dumped, lowering total system capacity. The amount dumped is likely to be considerable. Zhang (2010) points out that as penetration increases beyond middling levels the amount of dumping rapidly increases. He estimates that for a CSP sector providing 50% of power 11% would be dumped but this would rise to 43% at 100% penetration.

In addition to this storage rate issue the UCTE plot shows several lengthy periods when German wind output is well below average. In fact there are almost four periods of one month when it is hardly significant. If stored wind energy was to maintain supply through the July-August instance storage volume would have to be more or less big enough to replace two-thirds of the average wind contribution for one

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[☆] No organisations funded this research.
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http://dx.doi.org/10.1016/j.enpol.2017.07.061
Received 10 May 2017; Received in revised form 21 July 2017; Accepted 29 July 2017

month.

The magnitude and implications of these two factors, storage rate and volume, could easily be overlooked. They are illustrated by a study of the Irish wind system by Connolly et al. (2012). Irish demand is on average 3.5 GW. Fig. 22 in Connolly et al. shows that 2 GW of wind capacity would enable wind to contribute 20% of demand without storage. However for the contribution to be 96% pumping capacity would have to rise to 9 GW and storage to a surprising 500 GWh. In other words as wind penetration rises above 50% of demand pumping capacity and storage required rise at an accelerating rate, and if wind was to supply almost all demand then pumping capacity would have to be 2.7 times total national power demand and there would have to be so much storage that it could meet total demand for 6 days. Note that Ireland is possibly the best wind region in the inhabited world.

The situation would be less acute for a highly integrated renewable system extending across Europe but the whole continent is prone to periods of stable, cold and cloudy weather lasting weeks. Miskelly (2012) has pointed out that even in Australia with its favourable renewable situation weather tends to be uniform across large areas. His analysis of the Australian situation shows that at times a wide trough of low wind energy would impact on all eastern states at the same time, weighing against transmission of large amounts of surplus power from poor to good regions.

Often the costs commonly stated for existing storage systems do not take these two factors into account. They usually refer to systems where a steady surplus input, for instance from coal or nuclear plant running at constant rates during the night, can be stored temporarily in a large water supply dam, to be used when demand peaks next day. These costs would in general be quite misleading if applied to renewable sources, because they involve pumps that can work at their ideal constant and relatively low rate for many hours, with no need to pump at a high rate to capture fleeting surpluses, and costs do not involve a need for sufficient storage to substitute for wind supply etc. for several consecutive days. In addition existing systems do not have to cope with varying energy surpluses, for instance as wind surpluses continually vary. This would involve constant acceleration and deceleration of large volumes of water within pipes, detracting from system efficiency.

Another important preliminary concerns the large amount of storage likely to be needed to enable 100% renewable supply. Pickard and Abbott (2012) suggest 2 GW for each GW of generating capacity, the findings by Lenzen et al. (2016) indicate that about 65% of demand would have to come from storage for 5 consecutive days. Connolly et al. find that if wind was to be Ireland's sole input sufficient storage to meet total demand for six days would be needed. The Australian Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Energy Networks Australia (2017) say that at times storage would have to meet total demand. As noted above, the UCTE plot for German wind input shows periods of up to one month when storage would have to substitute for wind input.

Some studies have given the impression that the storage task is tractable by stating it in terms of percentage of power generated. Palzer and Henning (2014) for instance refer to several findings that the percentage is in the range of 8–15%. This is misleading; what matters is the extent to which the stored energy needs to be accumulated quickly, the occurrence of periods when it must substitute for a high proportion of demand, and the cost of sufficient plant to perform these functions. It could be that a large amount of very expensive plant is needed to deal with a relatively few difficult periods in the year yet the total amount of energy delivered in those periods is not great.

3. Concentrated solar thermal (CSP) heat storage

The CSP component of the technology mix Lenzen et al. arrive at plays a major role in the derivation of conclusions re dealing with poor conditions, provision of storage capacity, total generating capacity needed, and thus total system cost. Given the complexity of the modelling and computing tasks involved in the Lenzen et al. analysis it made sense to proceed with commonly held assumptions regarding CSP. However there are reasons for thinking that some of these assumptions are far too optimistic.

There has been little discussion of the capacity of CSP to contribute in poor conditions. This is not necessarily a problem for generating companies as CSP performance in good conditions probably ensures economically viable annual output. However it is a problem for total system designers because they are tempted to rely heavily on CSP storage to maintain supply through poor conditions. As the issue is unsettled, neglected and lacking in clear evidence the following exploration is somewhat lengthy.

Unfortunately the companies developing CSP do not release detailed data on performance enabling clarification of core issues. Nevertheless there is evidence that performance in poor conditions is low. In their simulations Elliston et al. (2012, 2013) generally find CSP to be of relatively low value in winter. Even though they assume 15 h storage they say that in winter recharge of storage generally cannot provide for more than 5 h supply. Similarly De Castro (2017) reports on a four day period when all Spanish CSP could generate at only an average 1.5% of the peak rate.

The performance of the large scale Ivanpah central receiver system (392 MW) has been problematic, leading to doubts about its financial viability. (Martin, 2016; Danko, 2015, Dietrich, 2016, Danelski, 2015; Andrews, 2017.) De Castro (2017) provides evidence that output from both Ivanpah and Crescent Dunes has been well below that expected. For the latter a capacity factor of 0.5–0.7 was anticipated but de Castro says the average has been 0.12. A review by Andrews (2017) reports problematic performance by five western US CSP plants, including Crescent Dunes and Ivanpah. His Fig. 2 shows that average monthly capacity factors of all were between 5% and 10% in January, meaning that for lengthy periods capacity factors were probably much lower still.

Similar concerns arise regarding winter output from the Spanish Gemasolar project. (See Trainer, 2014.) Gemasolar has 15 h storage (also assumed by Lenzen et al.), but the general system power storage task could at times be to meet much of total demand over several days. (See below on Fig. 5 in Lenzen et al.) In addition Gemasolar is permitted to generate 15% of output using gas and the available output data is likely to include such use, increasing concern about what its lowest winter performance might be (below.). Thus the extent to which CSP could be relied on when most needed for back up purposes in a strictly zero-carbon regime is doubtful.

There are three important elements in the Lenzen et al. study which are questionable but could be refined when the approach is further elaborated. Again it would seem that plausible adjustments here would raise estimated total system final costs significantly.

3.1. The capital cost assumption

The figure given for 6 h storage (from AETA, 2012 and 'Scenario 1 2030' in AEMO, 2013) represents a large (56%) fall from the present cost given by AEMO. The 20 MW Gemasolar Plant in Spain was the first to be equipped with15 hour storage, assumed by Lenzen et al., and its capital cost has been reported as $419 million US, or a remarkable $21,000/kW, three to four times the Lenzen assumption (Wilson, 2011). One would expect this first-of-a-kind cost to fall in future, but over the past ten years or so there seems to have been no tendency for CSP capital costs to fall. In fact Fig. 9 in the review by Bollinger and Seel (2014) show that there has been a c. 25% increase between 2007 and 2014. Thus an appropriate future capital cost estimate for CSP is more uncertain than for wind or PV and the 56% lower than present figure used in the study is implausible.