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The economics of different generation technologies for frequency response provision☆

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HIGHLIGHTS

- The variation in cost for generators depending on loading level is considered.
- Coal and combined cycle gas turbines (CCGT) generators are economically acceptable for part loading.
- Frequency response payments cover part loading costs for coal, CCGT and nuclear.
- Additional capabilities of pumped storage must be considered in cost comparisons.
- System wide costs are optimised for the Winter peak and Summer trough in 2016 and 2020 Future Energy Scenarios.

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ABSTRACT

The provision of reserve generation is an essential part of maintaining a reliable electricity system and has become an increasingly difficult task with the growing contribution from variable energy sources. Ensuring the cost of balancing supply and demand is minimised is an important aspect, requiring an understanding of how generator costs vary depending on their operation. This paper considers the cost of part loading different generator types, providing a cost breakdown and description of the Levelised Cost of Electricity method of analysing generator costs. This delivers cost-loading level curves for the generator types with the largest contribution to the UK generation portfolio which can be used to perform economic optimisations for generator scheduling. The holding payment for provision of frequency response, an aspect of maintaining balance between generation and demand, is separated by generator type and compared with the calculated part loading costs. To demonstrate the effect on system costs the Winter peak and Summer trough in 2016 and the Future Energy Scenarios in 2020 are considered with maximum and minimum generator numbers connected. Provision of sufficient generation to meet demand and reserves are optimised to reduce costs in each scenario.

1. Introduction

The cost of electricity provision combines several aspects; including infrastructure, production and ensuring a secure supply. As the contribution from variable energy resources (VER) increases ensuring a secure supply will become a bigger challenge, requiring more flexible generators to guarantee there is sufficient reserve available on the system [1–3].

As demand fluctuates supply must follow, which requires reserve available for unpredicted changes. Balancing services have cost the UK £62.49 m and £71.10 m in January and February 2017 respectively [4], with £24.7 m and £20.8 m spent on ensuring reserves could respond to unanticipated demand changes. This response occurs over a variety of time frames; frequency response over the first few seconds whilst short term operating reserve responds over several minutes. These reserve services require head room available to respond and the reserve payment must cover the loss of income generators experience through reducing their output, which is a focus for this paper.

In recent years a move away from traditional thermal generators providing mandatory frequency response towards commercial frequency response providers has occured. Energy storage is potentially competitive in the commercial frequency response markets in relation to batteries [5], community energy storage [6], electric vehicles [7] and the utilisation of storage alongside wind farms increases their frequency response and inertia capabilities [8–10]. Batteries do not possess sufficient capacity currently to cover reserve requirements but energy

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storage, in the form of pumped storage, will be considered in this paper. In contrast demand side response theoretically has capacity equal to the entire system but control is currently limited, with only large industrial and commercial loads responding [11]. With the introduction of smart grids [12], usage of responsive refrigerators [13] or alternative frequency control methods [14] this may be an option in the future.

The provision of flexibility by VER is limited, VER is considered the cause of imbalances rather than a source of ancillary services [10,15,16] and cost allocation to alleviate this problem is under consideration [3]. However numerous methods have been proposed to utilise this resource [10,17–19] which will become an increasingly important reserve to exploit in the future, with increased environmental costs and penalty payments associated with emissions. This paper will only consider wind providing reserve through a part loading technique, rather than the incorporation of storage or solar, as this is the only large scale VER reserve method currently available in the UK system.

Previous research into economic reserve provision has focused on ensuring there will be sufficient flexible generation available with an increase in VER [1,18,20], optimising the future generation portfolio and predicting the costs associated with this new generation mix [21,22]. These papers consider a variety of costs but ignore the cost incurred by part loading the generator initially. This cost is a major contributor to the reserve payment, varying considerably between different generators and loading levels.

In this paper we provide cost curves for part loading the largest contributors in the UK generation portfolio. To demonstrate the effect this has on the total system cost scenarios with maximum and minimum numbers of part loaded generators at the Winter peak and Summer trough in 2016 and 2020 Future Energy Scenarios (FES) [2] are quantified. These scenarios also consider frequency response reserve requirements and provides a method for optimising generators to meet demand and reserve requirements based on specified generation mixes. This method can be utilised to ensure system costs are minimised whilst maintaining safe and secure operation.

Section 2 explains the main contributors to part loading costs, presents the cost curves for different generator types and considers the change in generation mix over the last few years in the UK. In Section 3 typical holding payments for mandatory frequency response in the UK are presented and compared with the cost incurred from part loading generators. Section 4 considers the total system costs in both 2016 and 2020 scenarios with maximum, minimum and optimised numbers of generators to meet demand and reserve requirements. The conclusion to the paper is presented in Section 5.

2. Part loading cost

There are multiple contributors to the cost of electricity production, with different cost aspects dominating each generator [23]. Past costing analysis focused on capital, operation and maintenance (O&M) and fuel costs to provide estimations for electricity production [24,25]. There are also assessments of the startup costs [1] which must be considered when looking at the overall system, but are not relevant for the part loading of individual generators.

The capital cost is a fixed value, including the costs from the planning stage of a new generating plant to the point of commercial operation [26]. It is a major component for nuclear power stations, contributing 60–70% of the overall cost, due to their significant construction time, 8.63 years in the UK [25,27]. However coal and combined cycle gas turbine (CCGT) plants, 1–2 years [28] and 2.5 years construction time respectively, have 30–40% of their total cost contributed by their capital investment [26]. Renewable generators also have high capital costs depending on the site chosen [29]. The typical capital cost for several generator types in the UK can be seen in Fig. 1.

The O&M cost can be split into variable and fixed costs: Variable O&M costs change in relation to electricity production, such as replacement of parts, whilst fixed remain constant, such as wages for plant

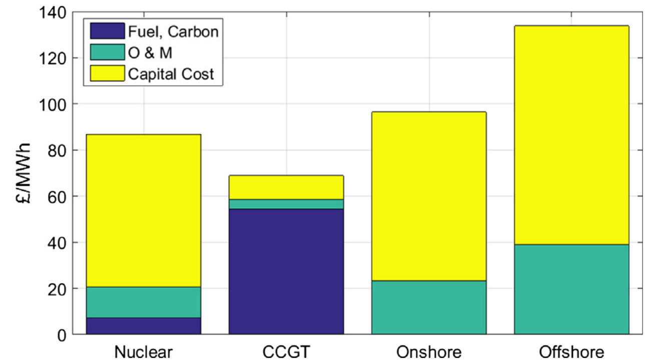

Fig. 1. Cost breakdown for different generator types [26,33,34].

personnel [25,30]. The fuel cost can be considered a variable O&M cost. Coal and CCGT plants have a significant contribution, 50–65% [26,31], from the price of fuel whilst nuclear is relatively low and stable, 5–10% of the overall cost. Renewable generators, such as wind, have neglible fuel costs, as shown in Fig. 1, but the maintenance, in particular for offshore wind farms, is substantial due to the challenges associated with their location. Another operational cost is the carbon price, paid by fossil fuel plants to encourage the reduction of CO_2 emissions. In the UK in 2017 the carbon price is £18 per tonne of CO_2 released [32].

The efficiency of a generating unit is plant specific and linked with the conversion of fuel into useful energy [33]. It changes over the operation of the plant dependent on several factors, including the loading level and maintenance.

In this paper the capital, O&M, fuel and carbon costs are considered for each generating type, with the efficiency linked to fuel usage where appropriate.

2.1. Cost quantifying method

Levelised Cost of Electricity (LCOE) is a tool used to assess and compare options with regards to various costs on a common base [35–37]. It can consider a wide range of costs but typically considers the planning, construction, operation and the decommissioning stages of a generating plant for a lifetime output power. This is used to choose between different design or investment options, such as the sizing of PV panels for a microgrid [35] or offshore wind turbine design changes [36,37].

An alternative tool is marginal pricing, used to quantify the cost to produce an extra unit of electricity by considering the additional operational costs this would induce [38]. Marginal pricing is commonly used in market applications, where system marginal cost is used to refund market participants for their services or as an aspect of generator scheduling [39,40]. The lack of a common base to compare between different generators makes it undesirable for this particular application.

Life-Cycle Cost Assessment can be used as a costing method for generator options [23,25,41] taking into account the various costs throughout the lifetime of the generation plant. However this method does not provide a common base, typically providing a cost per generator [25], and often incorporates environmental costs into the analysis [23].

To consider different generator types and the effect loading levels have on their lifetime cost Eq. (1) has been formed based on the LCOE tool. It details how the different cost contributors are combined to find the total £/MWh cost each generator must charge to recover their investment depending on the average lifetime loading level.

$$Cost_{Loading} = C_{Capital} \times \frac{E_{Expectedlifetime}}{E_{Actuallifetime}} + C_{O\&M} \times \frac{E_{Expectedlifetime}}{E_{Actuallifetime}} + C_{Fuel} \times \frac{1}{\eta} + C_{Carbon} \tag{1}$$

where $Cost_{Loading}$ is the cost of electricity production at a chosen average loading level, $C_{Capital}$ is the generator capital cost, $C_{O\&M}$ is the generator