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Analysis of Coal Conversion to Biomass as a Transitional Technology

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ABSTRACT

The dominant transitional path towards a low carbon electricity industry for systems which have been heavily dependent upon coal is through its replacement by large scale wind farms and the widespread emergence of distributed solar. In this pathway, maintaining resource adequacy in the context of increased intermittency in generation has become a major concern. This paper examines this requirement to maintain resource adequacy and compare the costs and carbon impacts for new gas turbines or biomass conversions to achieve this in an expedient transitional way. This is formulated as a policy optimization in which the imperative is to replace existing coal with a renewable alternative (in this case study, wind) and to maintain the system security at the existing level, and thereby find the optimal subsidies, either as energy credits ("green certificates" or "contracts-for-differences") or capital benefits ("capacity payments" or tax allowances). In a model of the GB system, the results show that that biomass-conversion outperforms investment in peaking gas turbines to deal with the transitional economic externality of extra reserve costs. In particular, the results suggest benefits of 10% lower costs of subsidies, 70% lower implied costs of carbon, and a reduction of 18% in wholesale power prices.

Keywords: Renewable Energy, Biomass, Investment, Security, Carbon Price

1. Introduction

Managing the transition of a carbon-intensive electricity industry towards low, or zero, carbon emissions has become a delicate balance of policy initiatives and long-term commitments. Whilst substantial subsidies have been provided to support the early stage innovations of renewable energy technologies, wind and solar in particular, a consequence of these subsidies has been a structural change in the wholesale market economics leading to lower revenues and asset impairments for incumbent fossil fuel generators [1, 2, 3]. As a consequence, further subsidies, usually in the form of capacity payments, have been required to ensure that sufficient generators remain operational and to incentivize the extra reserves that are needed to cope with the intermittency of wind and solar production [4, 5, 6, 7, 8]. The sum of these subsidies, both for stimulating the innovation in new, clean technologies and maintaining resource adequacy, together with the associated network infrastructure upgrading, are inevitably subject to government budgets and considerations of consumer impact (e.g. the Levy Control Framework in the UK [9], and the Energiewende in Germany [10]). Within a framework for medium or longer term decarbonisation of the sector, e.g. by 2030 or 2050, policy support for decarbonisation therefore reflects, implicitly or explicitly, a dynamic policy optimization of subsidy design subject to costs, resource adequacy and carbon mitigation constraints.

In the context of this, investment in gas turbine facilities to provide extra reserve capacity, as intermittent wind and solar replace coal, is often regarded as a viable transitional process, notwithstanding its carbon emissions [11, 12]. The "open cycle gas turbines" (OCGTs) are relatively low capital cost, easy to install and with the low load factors associated with peaking facilities, they are usually presumed to be the best economic option to provide the extra capacity. Indeed, the OCGT "levelised" cost is widely used a reference price for capacity payments and auction parameters, for example when governments are seeking to procure firm capacity to meet annual resource adequacy targets [13]. Nevertheless, gas generation is not low carbon, and more reserve is required as intermittent renewable resources replace the firm coal facilities.

In contrast, whilst the conversion of existing coal facilities to biomass, via burning wood pellets, is also a low-carbon initiative attracting policy subsidies [14], it has not been considered in the same way as OCGTs for providing reserve. But these coal-to-biomass conversions have a number of attractions: the biomass cycle, if implemented in a fully compliant way, is low carbon; the conversion costs are substantially smaller than new build; new sites and new infrastructure connections are not required and the business model for those incumbent coal generating companies does not have to change substantially. Furthermore, with the extensive global coal reserves and worldwide coal generation expected to remain substantial through to 2040 [15], biomass conversion has an appealing role to play in gradually moderating the emissions from the large stock of coal plants in operation. Nevertheless, it is clearly transitional and inferior to a complete low-carbon solution, to the extent that the full supply-chain, carbon-footprint for wood pellets can be significant depending upon the mode and distance of transportation.

In the future, on the other hand, it has been well-recognized that allied to carbon capture and storage (CCS), if indeed CCS were to fulfill the long-standing aspirations of commercialization [16], biomass coal conversion would offer the possibility of being a net reducer of carbon emissions [17]. But that remains speculative, as do several other new technology solutions to maintain reserve adequacy. Storage is developing rapidly, as well as the aggregation of demand side response into “virtual power plants”, but not yet at a scale to keep pace with, and thereby provide the reserve support for, the penetration of new wind and solar. In the longer-term, renewable energy allied to storage is a desirable end-stage, but the transition is not immediate. Thus, in the meantime, new-build gas turbines continue to be advocated as the transitional peaking technology.

The starting point for this paper is therefore the basic observation that the dominant path towards a low carbon electricity industry for systems which have been heavily dependent upon coal is through its replacement by large scale wind farms and the widespread emergence of distributed solar [15]. In this respect, whilst their introduction has been driven by policy determination and subsidies [18], an externality of both of these intermittent technologies is the need for extra reserve. This paper examines this requirement to maintain resource adequacy and compare the costs and carbon impacts for new gas turbines or biomass conversions to achieve this in an expedient transitional way. This is formulated as a policy optimization in which the imperative is to replace existing coal with a renewable alternative (in this case study, wind) and to maintain the system security ("outages") at the existing level, and thereby find the optimal subsidies, either as energy credits ("green" certificates or “contracts-for-differences”) or capital benefits ("capacity payments", grants or tax allowances). Further, the analysis does not presume risk-neutrality on the part of investors but aversion to downside risk, as manifest by the metrics of rating agencies (e.g. [19, 20]). Apart from the social welfare costs, the analysis computes the full supply chain implied cost of carbon for the various alternatives. The model reveals that that biomass-conversion outperforms investment in OCGTs to deal with the economic externality of extra reserve costs. In particular, the results suggest benefits of 10% lower costs of subsidies, 70% lower implied costs of carbon reduction, and a reduction of 18% in wholesale power prices.

This paper therefore makes several research contributions. From an analytical perspective it develops a methodology to analyze the subsidy costs over time to replace coal with wind and at the same time maintain a reserve margin expressed as a loss of load probability (an expectation of 3 hours per year is the UK target). Furthermore, the financial viability of the replacements investments is ensured by a risk constraint on the capital coverage ratio. Therefore, the formulation involves a dynamic, multistage optimization with probabilistic risk constraints. From this model, a new comparison of energy versus capacity subsidy schemes is provided and concludes in favor of the latter. In terms of technological context, this research is the first to compare biomass conversions and gas turbines as transitional alternatives within this optimized policy framework. It concludes that the former is beneficial in terms of lower subsidies, lower wholesale prices and a lower implied cost of carbon reduction.

The next section presents the formulation for the investment simulation. This is applied to a realistic case study based up the British system which has indeed been characterized by policy support for large scale offshore wind to replace an accelerated retirement of coal facilities. Whilst being a particular application, the policy insights are generalizable. Subsequent sections consider the comparisons of biomass and gas for complementing the wind replacements with their extra reserve requirements. The analysis computes the implied cost of carbon reduction, and also considers a variation in which policy-makers are somewhat risk averse in optimizing the costs of subsidy design against the twin constraints of a decarbonisation pathway and resource security. Final observations and comments conclude the paper.

2. Model Formulation

The stylized setting is an electricity industry (e.g. in Britain) seeking to replace its existing coal generation with offshore wind, at minimum cost of subsidies, whilst maintaining a constant security of supply margin. The analysis is a comparative static one in the sense that no forecasts are presumed for future events and parameters, rather a power industry as it exists in a target year (2016/17) is systematically varied by the replacement of coal by wind, plus the addition of either gas or biomass to maintain the same level of security. Its economic performance is determined by a market price formation model which is simulated by Monte Carlo variation of all uncertain variables.

In other words, it provides a focus on the effects of key variables and current risks for a set of target year variations, without speculation on future scenarios.

Within this target year model, revenues from the market simulation model provide the basis for determining the amount of subsidies needed for the investments in new capacity to be viable. Whilst the conventional NPV of a facility gives the economic value, it is well-observed that a positive NPV is often not sufficient by itself to motivate investment in practice. Often, an incentive to invest will only occur if the debt service coverage ratios required by senior lenders can be maintained [21]. The debt service coverage ratio is defined as the total cash flow available to service debt divided by the debt repayments in a given period, usually one year, as in [20]. A new investment is therefore considered to be feasible, in the sense of being financeable, if this coverage risk is below a critical level. Specifically, a proxy criterion of 1.2 is used for capital coverage at 90% probability, implying that in any year the risk of the annuitized capital costs not being covered operational earnings plus 20%, should be less that 10%. Various wind farm financings corroborate these numbers [22, 23, 24, 25]. However, it is recognised that although such financial metrics tend to be idiosyncratic in practice, the particular values are less important to this analysis than the general principle of such a metric being applied in a consistent way across the policy variables. In particular, such a metric requires a risk simulation element to the market modelling.

Three different case studies have been considered, which are detailed below. All of them have the same purpose (to fully remove the installed capacity of coal plants and replacing with offshore wind), and for that, two different approaches are analysed: replacing the total productive capacity of coal, or just the actual production in the base year. Moreover, extra reserve capacity is required to prevent the increase of unserved energy (outages), due to wind intermittency. Extra capacity can be provided by a peak technology, the "open cycle gas turbines" (OCGTs), or a flexible baseload technology, biomass (in this case, from the conversion of existing coal facilities, via burning wood pellets). These two alternatives are evaluated for each scenario.

The research questions are analyzed in this paper with reference to the British wholesale power market when, *ceteris paribus*, the installed capacity of coal plants is progressively replaced by offshore wind, taking 2016 as the base year. The simulation proceeds as follows. Random exogenous variables are simulated. These include the demand (hourly), the availability of each generating unit, including wind facilities, each fuel (inter-correlated), and the carbon emissions price. Hourly demand distributions are obtained from the actual historical half-hourly data available from National Grid.

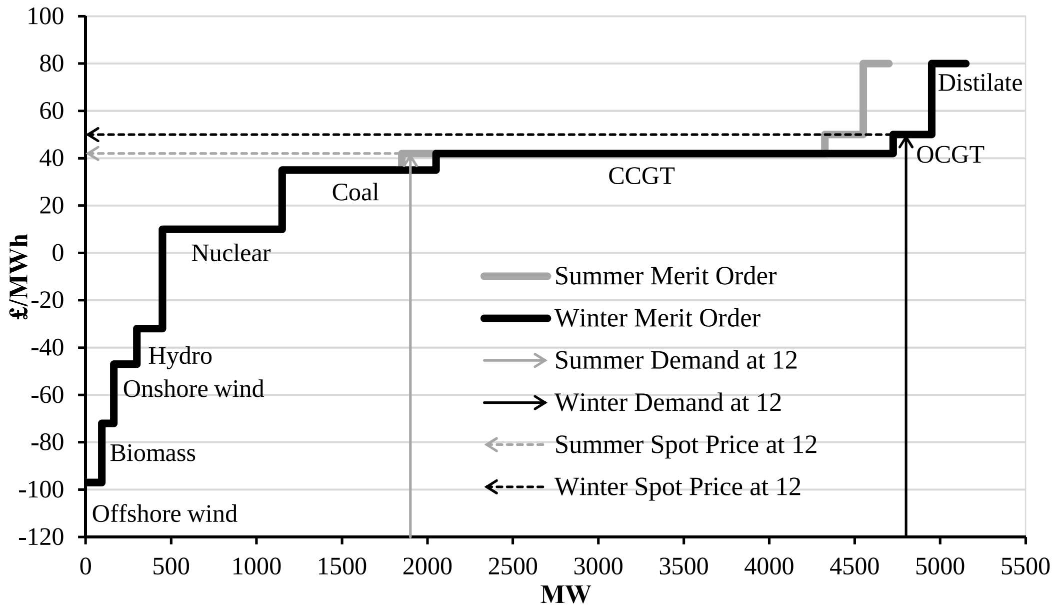

Fig. 1. Average British Merit Order in 2016.

The merit order supply stack is constructed from all 320 generating units available in 2016 ordered in ascending order of marginal cost (from least to most expensive). For market price formation, nuclear is always assumed to be at the bottom of the stack, although its marginal cost is higher than wind. This ensures that nuclear output is not curtailed. The market, as indicated in Figure 1, is cleared by having all active players take the price of the most expensive active generating unit needed to meet demand. If the demand is higher than the cumulative available capacity, an "outage" is recorded.

Production uncertainty of each technology is simulated from binomial distributions, wind speed (used for estimating wind production) is represented by Weibull probability distribution functions, and fuel prices are specified by lognormal distributions. Wind speed is converted to power according to a typical wind-power nonlinear transfer function, as Figure 2, following [26,27,28]. The portfolio averaging of extensive wind farm penetration is modelled by considering two regions in GB, north and south. From studies on wind speeds in geographic locations [29] an output correlation index of 0.7 is taken for plants in the same geographic areas within the north or south, and an index of 0.1 is used as the output correlation coefficient between the north and south plants. New offshore wind generation is assumed to be distributed evenly between north and south.

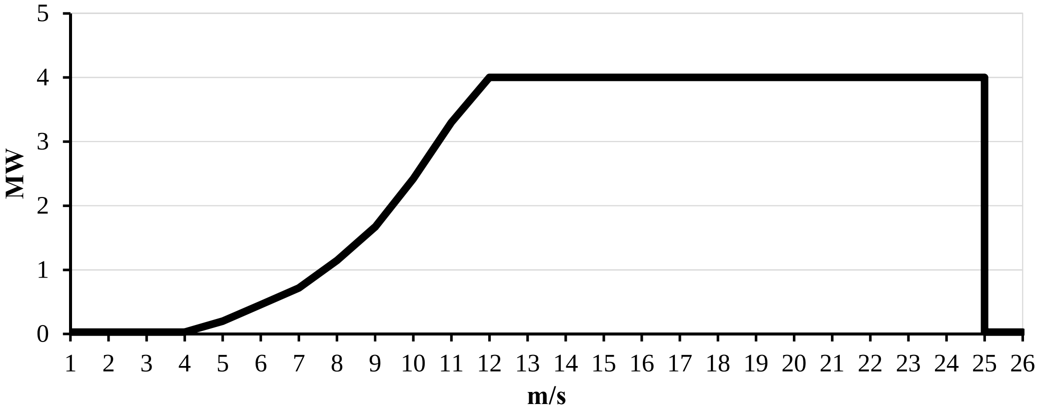

Fig. 2. Generation Output for a Typical Turbine as a function of Wind speed.

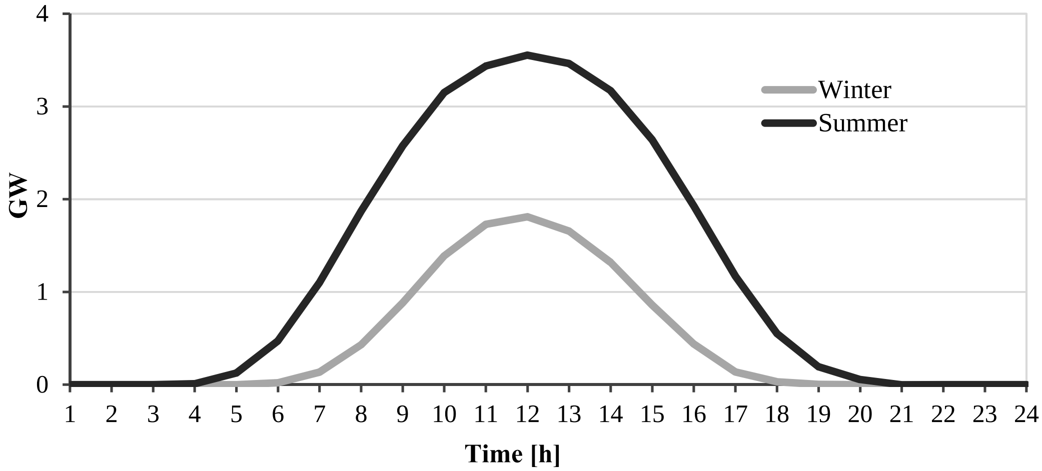

Fig. 3. Average Daily Solar Generation in 2016.

The hourly photovoltaic production distribution functions are obtained analogously, using the 2015 historical data [30]. In Figure 3, PV generation obtained from these distribution functions is represented. This PV production is subtracted from the demand in this modelling procedure.

In the model, all (320) generating units offering into the market are included from the very small biomass, onshore and offshore wind facilities to the large nuclear stations. Installed capacities, capital costs, annual fixed costs, lifetimes, availabilities, carbon intensities and heat rates were consistent with various sources [13,14,31,32,33,34,35] and hourly demand for 2015/16 was taken from the National Grid[1]. The basic fuel cost parameters were specified by lognormal distributions with the follow mean and standard deviations: coal (\$/tonne 80, 8); gas (p/therm 45,5); oil (£/bl 43, 4); ROC (£/ROC 45,4); and EUA carbon price floor (£/tonne 18,0). The within year correlations were estimated empirically as 0.6 for Gas and Oil; 0.6 for Gas and Coal; 0.8 for Coal and Oil.

No allowances were made for start-up costs. Transmission constraints do not factor into wholesale market prices, as they are part of the real-time system balancing

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[1] http://www.nationalgrid.com/UK

activities. No demand elasticity is assumed. Unplanned outages are simulated according to binomial distributions based upon average availabilities. Finally marginal cost clearing prices as simulated for the whole year were given a 15% mark-up to provide a good calibration to actual 2016 data.

Using the above annual price simulation model, the analysis proceeds by optimising the amount of extra reserve capacity needed to maintain the same security as in 2016 whilst replacing the coal with offshore wind. More precisely, the objective function (OF), which is minimised in the optimisation, is the mean value of the total subsidies required in the process of removing coal generation (1), subject to constraints. Total cost of subsidies (*TS*) is calculated as the sum of subsidies to new offshore wind and extra capacity. The subsidies can be either green certificates or capital grants.

$$min\{OF = mean(TS)\} \tag{1}$$

It is subject to a constraint (2), to maintain the security of supply. To do so, the limit on outages during the process is set as the risk of outages in the base year, based on the simulation of the model with 5,000 iterations to ensure a stable value. We found from the simulations that the appropriate base mean outage value (expected energy unserved) was 1050 MWh. Note that the precise British reliability standard of 3 hrs Loss of Load Expectation, has not been used, but the model maintains consistency with the status quo in 2016. The actual value of this expected energy unserved is not crucial to this analysis as the key results relate to the changes from a base level.

$$mean(outg) \leq 1050 \ \ [MWh] \tag{2}$$

The objective function is also subject to an investment constraint (3), to ensure an adequate profitability to investors in extra reserve capacity. In this case, a capital coverage ratio (CR) of 1.2 with a 90% confidence is considered.

$$percentile_{10\%}(CR) \geq 1.2 \tag{3}$$

Capital coverage ratios are calculated as the as shown in (4), where *PR* refers to annual profits, *G* refers to annual capital grants, and *PAY* refers to the annuitized capital payments (*ACP*) and fixed payments related to O&M, calculated as shown in Eq. (5), where *C* refers to installed capacity. The associated data are displayed in Table 1. In order to avoid issues of gearing, it is assumed for simplicity that the capital coverage ratio covers both debt and equity and this is discounted at a cost of capital to account for both.

$$CR = \frac{PR + G}{PAY} \tag{4}$$

$$PAY = (ACP + O\&M) \cdot C \tag{5}$$

TECHNOLOGY	Capital Costs (*CC*) [£/kW]	Interest rate [%]	Lifespan (*Y*) [Years]	ACP [£/kW]	O&M Costs [£/kW]
Offshore wind	2,800.00	7	20	264.30	48.00
OCGT	440.00	7	25	37.76	9.50
Biomass (conversion)	321.00	7	20	30.30	22.00

Table 1. Data to calculate annuitized payments.

Two types of subsidy mechanisms are considered. "Green Certificates" are an energy credit, widely used internationally and provide a supplement to the market prices for producers of renewable energy. They are known as Renewable Obligation Certificates ("ROCs") in the UK. An alternative to an energy payment is a capital payment on the investment. This can take the form of a fiscal benefit or a capacity payment. This as a "grant" in this analysis. Biomass could receive either an energy subsidy, ROC, or a capacity grant; but OCGTs can only receive capacity payments. In both cases, this model optimises the levels to ensure that constraint (3) is achieved.

3. Replacement of Coal by Offshore wind

In this transition scenario, total available production capacity of coal (*COA*) is replaced by offshore wind (*WOF*), following the formula described in Eq. (6), where *af* refers to the availability factor of each technology (coal, 87%; offshore wind, 45%; OCGT: 94%; biomass: 87%).

$$C_{100\%}^{WOF} = C_{0\%}^{WOF} + (C_{0\%}^{COA} - C_{100\%}^{COA}) \cdot \frac{af^{COA}}{af^{WOF}} = 4{,}705 + (13{,}737 - 0) \cdot \frac{0.87}{0.45} = 31{,}263 \tag{6}$$

Extra capacity requirements, either biomass or OCGT, are also optimised to satisfy the probabilistic security constraint. Installed capacity [MW] of coal, offshore wind, and OCGT or biomass, under 0% and 100% coal replacement are shown in Table 2.

TECHNOLOGY	0%	100%
Coal	13,737	0
Offshore wind	4,705	31,263
Biomass	2,226	4,653
OCGT	2,020	4,296

Table 2. Case 1: Capacities in MW for coal replacement based upon installed availability.

The above replacement is based on installed capacity adjusted by technical availability factors. However, with a high carbon floor price of £18/tCO_2 , the load factor of the coal plant in 2016 is low and so it would be appropriate to also consider the working hours (load factor) replacement of coal by offshore wind. In this second scenario therefore, coal energy production is replaced by offshore wind, following the formula described in (7), where *wh* refers to the 2016 working hours of each technology (coal: 1,200 hours, and offshore wind: 8,760 hours), again adjusted by technical availability factors. Installed capacities [MW] are detailed in Table 3. Evidently much less wind is installed but more peaking plant is required to maintain the same security.

$$C_{100\%}^{WOF} = C_{0\%}^{WOF} + C_{0\%}^{COA} \cdot \frac{af^{COA} \cdot wh_{0\%}^{COA}}{af^{WOF} \cdot wh^{WOF}} \tag{7}$$

TECHNOLOGY	0%	100%
Coal	13,737	0
Offshore wind	4,705	8,343
Biomass	2,226	11,318
OCGT	2,020	12,541

Table 3. Case 2**:** Capacities in MW for coal replacement based upon load factor.

To see the effect of the carbon floor at £18/tCO$_2$, the above scenario is repeated using an EU ETS market price average of £5/tCO$_2$. This reduces the coal generators' marginal costs to below those of the CCGTs and accordingly the average operational hours go to 5,379 from 1,200 hours, previously. Therefore, its production is higher in the base year, and more offshore wind is needed. Installed capacities [MW] are detailed in Table 4.

TECHNOLOGY	0%	100%
Coal	13,737	0
Offshore wind	4,705	21,013 (16,308 new)
Biomass	2,226	8,023 (5,797 new)
OCGT	2,020	7,616 (5,596 new)

Table 4. Case 3**:** Capacities in MW for coal replacement based upon load factor with low carbon price.

To assess the decarbonisation achieved in each of the three scenarios, the percentage of CO$_2$ emissions reduced is calculated. Estimates are used of the full supply chain carbon emissions per MWh generated, i.e. carbon emission intensities of 1.00 tCO$_2$/MWh for coal, 0.53 tCO$_2$/MWh for OCGT and 0.28 tCO$_2$/MWh for biomass. These are different from the carbon intensities used in the market price simulations (which are not based upon the full supply chain). This in the market, biomass is considered carbon neutral, but in the overall accounting, included are the total emissions from the cultivation, harvesting, processing and transport of the biomass feedstocks. And to follow the same criterion for coal and OCGT, final emission intensities of these two technologies are increased by 10% over their usual market levels to account for transport. Results for each scenario and alternative are represented in Fig. 4.

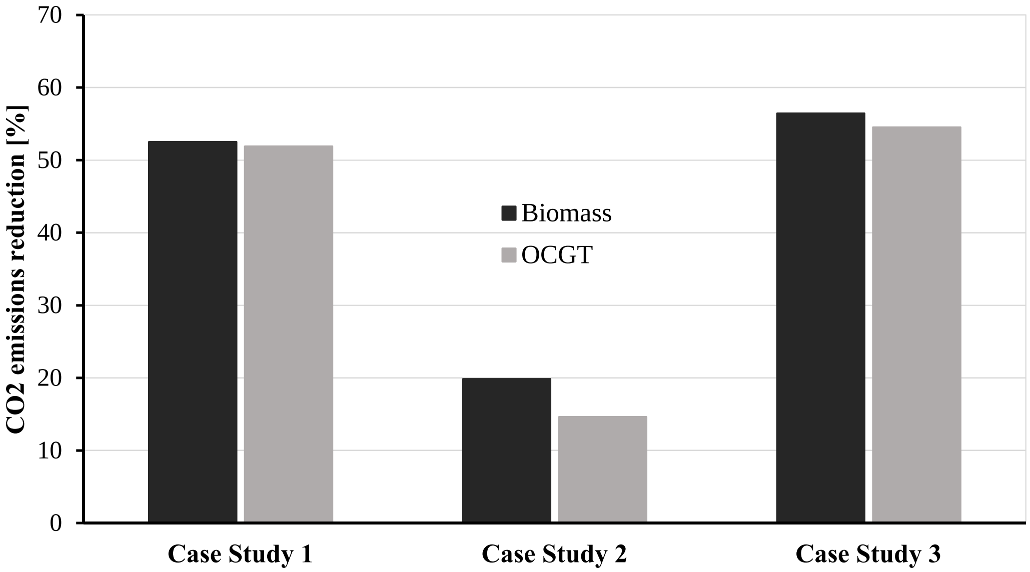

Fig. 4. Percentage of CO_2 emissions reduced according to replacement assumptions.

Replacing coal by offshore wind typically leads to a drop of wholesale electricity prices. However, when the amount of offshore wind introduced is small and a peaking technology with high marginal costs is used to provide extra capacity, spot prices might consequently remain at the same level or even increase. Moreover, the subsidy scheme used to pay the subsidies also affects prices. For that reason, in the following chart, biomass is divided into two groups: “ROCs”, for energy subsidies, and “Grants”, for capacity payments. The variation of daily average electricity prices is shown in Fig. 5. There is a beneficial effect on reducing prices for using biomass, and indeed against the background of the high carbon price floor of £18/tCO_2 in Case 2, the use of OCGTs to maintain security actually increases prices slightly.

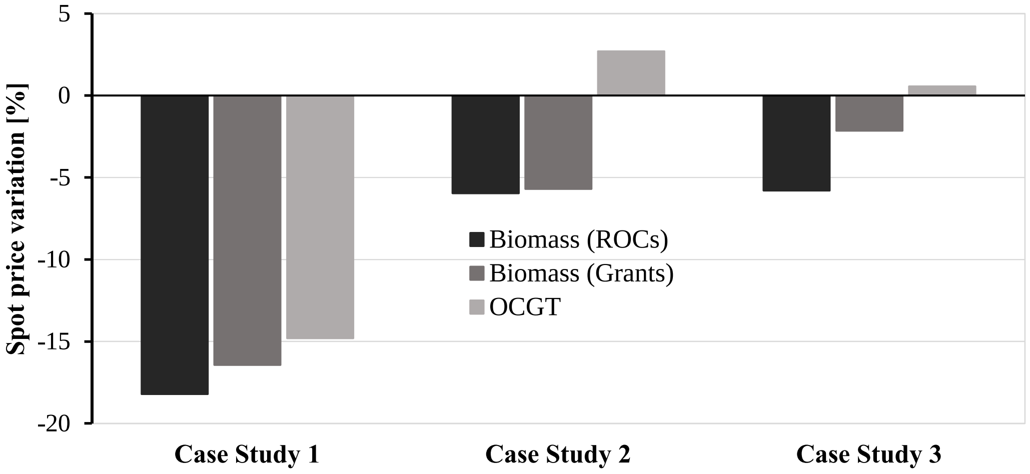

Fig. 5. Daily average spot prices variation.

In all scenarios, ROCs and grants for biomass and OCGT are optimised. However, the amount of subsidies to offshore wind is maintained at the same 2016 level (1.8

ROCs/MWh, i.e. about £80/MWh in addition to the wholesale price around £35/MWh), which is significantly higher than the optimised value of 0.3 ROCs/MWh for biomass). As a consequence, the larger the installed capacity of offshore wind, the higher the total subsidies. Although dominated by the cost of subsidising the wind with this base case of high ROCs, it is discernible in Case 2 that supporting biomass with capital grants can lead to a marginal saving compared to using green certificates, and compared to maintaining security via OCGTs.

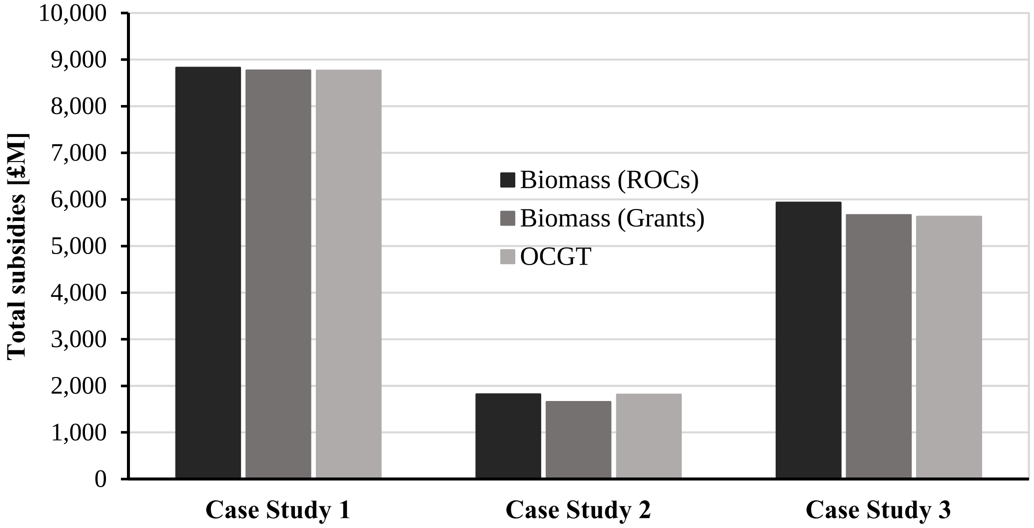

Fig. 6. Total subsidies.

The base year 2016/17 was a year of rapid change in support levels for offshore wind. By September 2017, ROCs had been replaced for offshore investment by Contracts for Differences. These were determined by an auction which cleared at £57.5/MWh. Fig. 7 shows the effect of this lower subsidy level, but note that the differences between the Cases do not change.

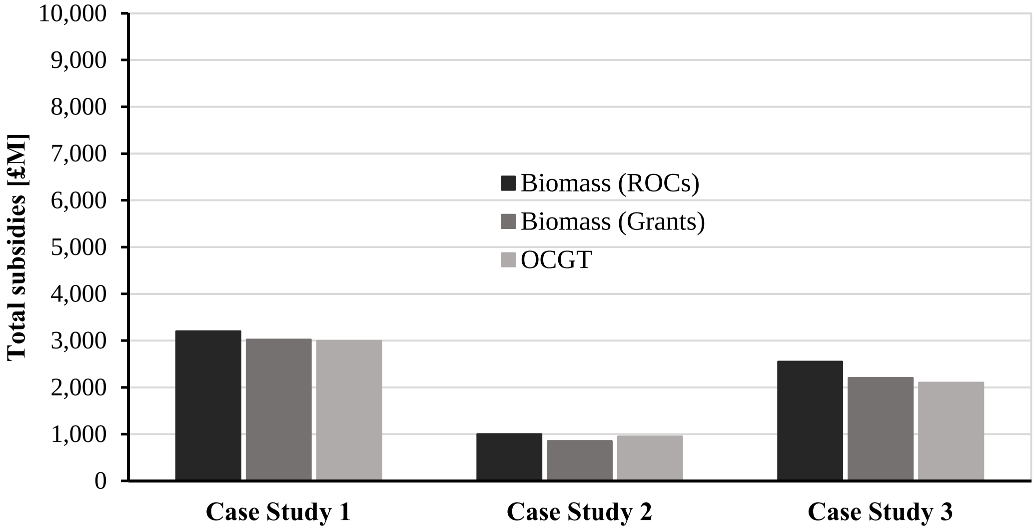

Fig. 7. Total subsidies with CfD policy for offshore wind.

Finally, Fig. 8 shows the ratio between total subsidies at the 2016 level (in Fig 6) and the CO_2 emissions reduced to produce an implied cost of carbon (£/tCO_2) for the transition under the different cases. Evidently, there is a much higher implied cost of carbon for the transition if security is maintained with OCGTs compared to Biomass in all cases, but particularly against the background of the £18/tCO_2 carbon price floor. With biomass, the implied cost of carbon is around £59/tCO_2 if energy subsidies are used or about £55/tCO_2 with capital grants compared to about £155/tCO_2 if gas is used for the security. Note that with the lower September 2017 CfD prices for offshore wind, these implied carbon costs would be reduced substantially to about a third.

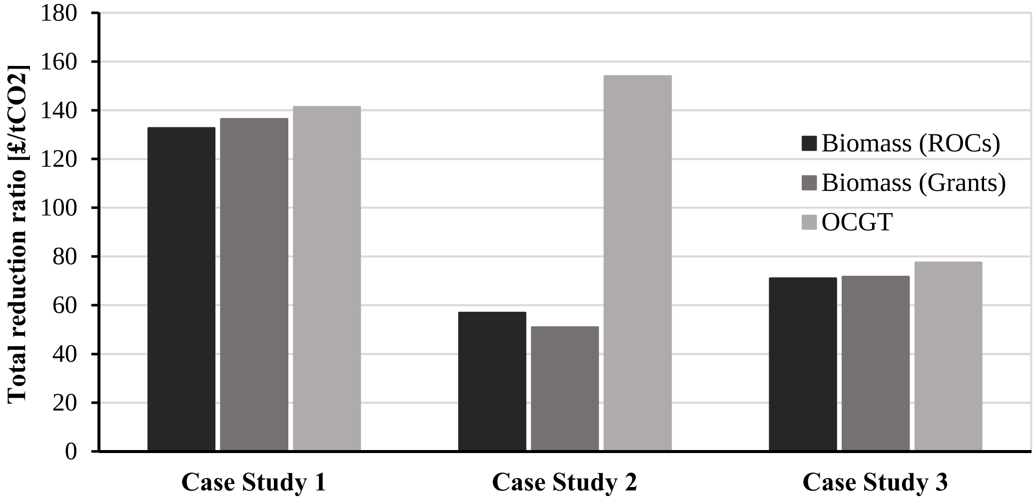

Fig. 8. Cost of carbon reduction.

Whilst the main result of this modelling is with regard to the value of biomass conversions, compared to new OCGT facilities, for maintaining security during a coal phase-out, these results also show that subsidies need to be slightly higher if they are paid as energy benefits (green certificates, ROCs, feed-in tariffs or contracts for differences) compared to capital grants (capacity payments, fiscal benefits). This is explained by the intrinsic uncertainty of the energy-based subsidies, where dependence on the different parameters mentioned previously increases the volatility of the cash-flow received by generators. This effect can be observed in Fig. 9, where the coverage ratio probability distributions for the Grants and ROC cases are compared. Higher volatility produces more disperse coverage ratios from a wider distribution, so the tails are longer and a 10% percentile of 1.2 is more difficult to achieve. Thus, biomass requires higher subsidy with energy credits compared to capital benefits.

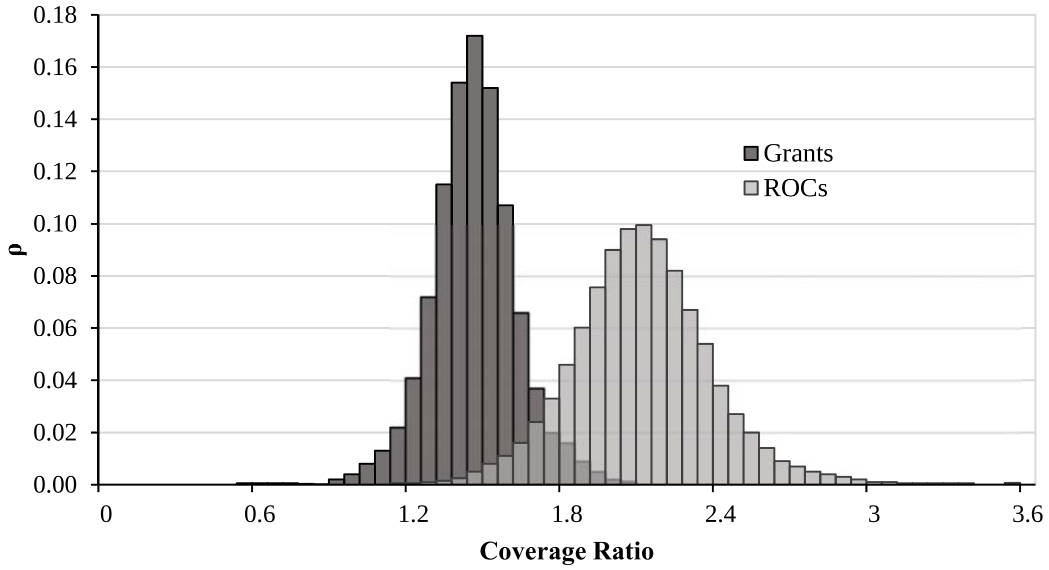

Fig. 9. Coverage ratio probability distributions.

Furthermore, important results are obtained regarding optimal ROCs in this analysis: the ROCs required to get a coverage ratio of 1.2 is around 0.3 ROC/MWh, much less than the 1.5 ROC/MWh being paid in 2016.

4. Conclusions

This analysis points to positive considerations for biomass conversion if coal facilities are being phased out and replaced by intermittent renewable energy resources. The need for a transition to maintain resource adequacy at a constant level, as measured by the expected energy unserved, can be optimized by the methodology developed in this paper. An application to the British context indicates that using biomass conversion compared to gas turbines to maintain adequate reserve levels leads to lower costs (according to this analysis, they could be up to 9% lower), lower prices (they could drop by 16-18%) and a lower implied cost of carbon reduction (it could be a 70% lower).

It should be emphasized that the analysis is a marginal one. It has looked at the operating reserve technology needed to maintain a system reliability target during an evolution in which a firm power source such as coal is replaced by a renewable facility such as wind or solar. The analysis is not about the widespread introduction of new-build biomass facilities for baseload, but instead, the conversion of the pre-existing coal plants, which are being decommissioned, to provide occasional reserve supplies. As such, the capital costs and supply chain implications are much less restrictive, and the practical feasibility of this analysis is plausible. Note in this context that some large coal facilities in Britain (over 2GW) have indeed been converted to biomass [36]. However, subsidies are required and the analysis shows that capacity payments rather than energy price premia are more efficient (the results suggest a benefit in the cost of subsidies of up to a

10%). This particular conclusion confronts conventional practice in many national markets.

Whilst this analysis has been derived from a stylization of the British context, the key indications are generalizable. The advantage of capacity payments over energy price premia is driven mainly by considerations of financing risk, being the reduction in the lower tail of the debt-coverage risk distribution. This is a general result, but presumes a focus upon financial risk in the investment decision. The context is that of private investors in a competitive power market, and this would not generalize to a public sector decision for a national monopoly. The latter case is however becoming much less common worldwide as competitive electricity markets mature.

Regarding the specific British case study of replacing coal by wind, it can be observed that other European countries are also progressing in this way, given the EU Directives for the low carbon and renewable energy transition. The scale varies however with, for example, France having a smaller installed coal capacity of 3 GW (vs. 14 GW, in the UK*)* and a slower development of wind [37, 38]. For Germany, however, coal is a major source of fuel for electricity generation with around 25 GW and there has been an active development program of wind, solar and biomass [39]. Subsides for renewable energies in both France and Germany have, however, been energy premia rather than capacity payments [40, 47]. Similarly for Spain with 14% provided by coal-fired plants and 20% coming from wind power [41, 42], and in The Netherlands with more than 30% produced by coal [44] and substantial offshore wind [45]. In other words, the European context presents various member states having substantial coal plant being imminently decommissioned and an expansion of their wind resources. Elsewhere in the world, in the United States, Australia and Asia, similar trends are evident.

Apart from the economic conclusions of the above analysis in favor of biomass conversion to maintain reserve levels, not costed are the attractions of a re-purposing of existing facilities. For asset owners, the attractions are clear [36]. Overall, however, one might have expected biomass coal conversions to be more widespread. Concerns about securing the supply chain are clearly very different to linking up with a pre-existing gas infrastructure. This study does not speculate on the future sustainability of biomass resources if biomass conversion were to become widespread, and these concerns may be overstated [46], but in the context of providing reserve to support wind and solar, the analysis does not envisage large-scale baseload demands upon the supply chain. It is clear furthermore that gas turbine installations are well established, reliable and well supported; whilst biomass power generation is more complicated by comparison. But with appropriate policy support this analysis suggests that biomass conversion can play a cost-efficient role in the energy transition.

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