



The relative system cost of biomass and offshore wind

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Executive Summary	1
1 Introduction	5
2 Definition of scenarios	7
3 How much wind is required to replace biomass?	11
4 Generation costs	13
5 Transmission costs	19
6 Operating reserve and back-up	25
7 Estimating the total cost to society	31
8 Estimating the cost to customers	35

The relative system cost of biomass and offshore wind

Figure 1.	Differences in cost between biomass and offshore wind in 2020	2
Figure 2.	Differences in cost between biomass and offshore wind in 2030	2
Figure 3.	National Grid's Gone Green scenario's installed capacity	8
Figure 4.	Estimated offshore wind capacity in 'Gone Green' scenario	14
Figure 5.	Average MWs operating reserve levels by system's proportion of wind capacity	26
Figure 6.	Operating reserve cost of per MW of installed wind	27
Figure 7.	Differences in cost between biomass and offshore wind in 2020	31
Figure 8.	Differences in cost between biomass and offshore wind in 2030	32
Table 1.	Key statistics from "Gone Green" scenario	8
Table 2.	Required incremental wind capacity	12
Table 3.	Summary of differences between offshore wind technology and location	15
Table 4.	Generation costs (£/MWh)	16
Table 5.	NPV of difference in generation costs	17
Table 6.	Estimated TNUoS tariffs £/kW of capacity	20
Table 7.	NPV of onshore network transmission costs	21
Table 8.	Current offshore local tariffs (£/kW)	22
Table 9.	NPV of local offshore transmission costs	23
Table 10.	NPV of operational reserve costs	28
Table 11.	De-rated capacity by technology	29
Table 12.	NPV of back-up generation costs	30
Table 13.	Wholesale prices by scenario in 2020 and 2030 (2014 £s)	37

Executive Summary

Frontier Economics has been asked by Drax Power Limited to assess the total cost of replacing a proportion of biomass conversion with an equivalent level of offshore wind investment in the overall generation mix, from a societal and customer perspective.

We have considered the following scenario. We have reduced the expected installed capacity of biomass in 2020 by 500MW, and assessed the increment of offshore wind that would be required to deliver the same level of renewable generation and hence contribute to the same extent to meeting renewables targets. As a result of differences in load factor, 500MW of biomass generation would need to be replaced by just under 855MW of offshore wind.

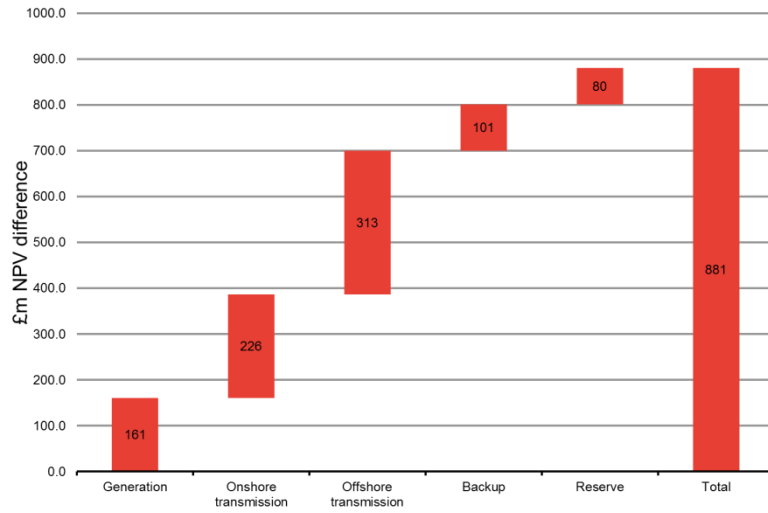
We then consider the difference in total system costs of displacing biomass with offshore wind in this way. Our assessment considered four cost categories:

- The levelised costs of both technologies;
- The transmission system costs of both (onshore and offshore);
- The back-up costs (i.e. the amount of generation required to support the additional increment of intermittent wind generation and hence ensure consistent levels of system security); and
- The reserve costs (i.e. the level of additional capacity required on the system to account for the more uncertain nature of wind generation).

Based on the range of assumptions we are making, in NPV¹ terms, replacing a single biomass generating unit with the equivalent investment in offshore wind would cost an additional approximately £650 million to £900 million. Figure 1 and Figure 2 below show a breakdown of the additional costs.

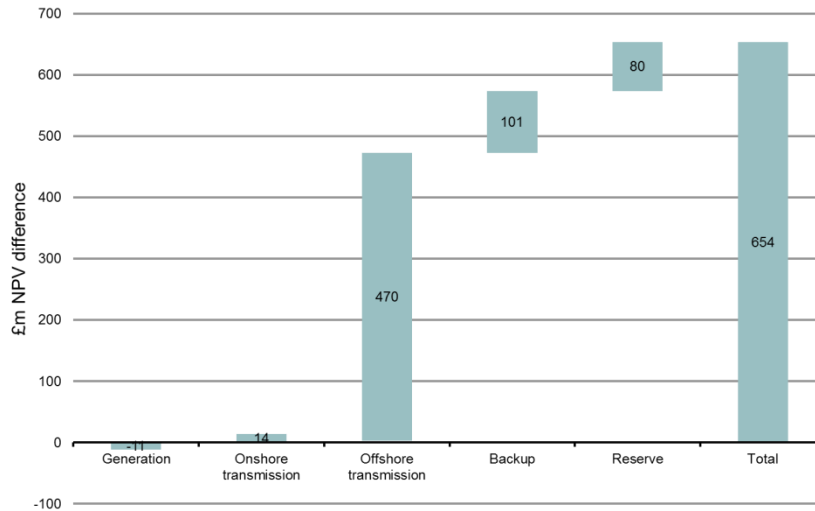
¹ DECC's "Electricity Generation Costs" report uses an operating period of 22 years for biomass, which is the time period we use for calculating the NPV.

Figure 1. Differences in cost between biomass and offshore wind in 2020



Source: Frontier Economics

Figure 2. Differences in cost between biomass and offshore wind in 2030



Source: Frontier Economics

The Figure shows that, based on the range of assumptions we are making, the key drivers of cost differences are:

- ▣ **Levelised costs (£-11 million to £161 million):** The upfront capital costs of offshore wind are significantly higher than those of biomass, outweighing the availability of lower cost energy once the windfarms are built.

Executive Summary

- **Onshore transmission costs (£14 million to £226 million):** We have assumed that biomass conversion would involve existing coal sites and therefore have zero connection costs. Given planned 2020 offshore wind connections, an increment of 855MW of offshore wind would be likely to connect to the onshore grid in Scotland. The onshore transmission cost difference therefore reflects the different transmission system investment costs associated with the respective connection points. We have not taken any account of the marginal increase in operating costs and losses on the network associated with moving transmission from the centre of the UK to Scotland.
- **Offshore transmission costs (£313 million to £470 million):** There are significant costs associated with building the transmission capacity necessary to connect offshore wind to the onshore transmission network.
- **Back-up costs (£101 million):** System back-up costs are significantly higher for offshore wind as additional (dispatchable) capacity would have to be built so that supply could match demand even in times when the incremental offshore wind sites were not generating.
- **Reserve costs (£80 million):** Offshore wind requires greater levels of system balancing reserves in order to manage balancing issues arising from wind forecast error.

Transmission costs are clearly a large part of the total difference which we estimate. We have had to make a number of assumptions (which we discuss in this document) in relation to those costs. In doing so, we have attempted to be conservative. However, we note that even without all transmission cost impacts, offshore wind would be more expensive than biomass conversion by £170 million to £342 million. And while estimating the transmission cost is inevitably difficult as a result of the need to make assumptions, it barely seems credible to suggest that there would be no network-related difference in cost.

We also considered whether part of the costs would be borne by producers, resulting in a lower impact on customers. We conclude that the vast majority of these costs will be borne by customers. We ran a wholesale market model to assess whether wholesale prices would be lower with more wind on the system, meaning customers benefit as a result of a transfer from producers. However, our modelling suggests that removing 500MW of biomass and replacing with the approximate 855MW increment of wind does not depress wholesale prices and hence there is no offsetting customer benefit in the form of lower wholesale prices.

Consequently, our analysis indicates that electricity customers in aggregate would pay an additional £650 million to £900 million in NPV terms as a result of a

move from biomass conversion to offshore wind. This is equivalent to a total cost of between £25 and £33 per household.

Given the scale of low carbon generation required to achieve 2020, 2030 and 2050 targets, a single technology cannot be expected to meet the overall requirement. To that end, a balanced energy mix will be required. We note that for biomass conversion, the four plants considered in this report (Rugeley, Eggborough, Ratcliffe and Cottam) have, at most, an approximate cumulative conversion capacity of 7,000 MWs. But, affordability is an important factor and costs are likely to increase further as more wind is added to the system.

We also note that Drax has plans to convert three units to biomass, amounting to 1,935 MWs of converted capacity. Based on the range of assumptions we are making, if our findings on 500 MW increment are scalable, then Drax's existing biomass conversions represent total savings to the UK of between approximately £2.5 billion and £3.4 billion compared to the equivalent generation from offshore wind.

1 Introduction

Drax Power Limited has asked Frontier Economics to assess the total cost of deploying an offshore wind farm compared to that for converting a coal unit to biomass from both a societal and a customer perspective.

The UK Government is currently reforming the electricity market in an attempt to reduce the sector's climate impact and meet the Government's commitment, under the EU Renewable Energy Directive, to source 15% of UK energy demand in 2020 from renewable energy sources.

Our analysis contrasts two different scenarios consistent with the UK meeting its renewables targets. The first is drawn from scenarios developed by National Grid to illustrate possible target-consistent futures for the electricity sector. We examine two snapshot years, 2020 and 2030. The second is a variation on the first, in which there is incrementally less biomass conversion and sufficient increases in offshore wind capacity to help make up the difference in terms of renewable generation. By contrasting these scenarios, we have estimated the difference in total costs:

- **impact on total costs to society:** We have assessed the resource cost implications of both scenarios, looking at the economic value of the resources used in each case; and
- **impact on customers:** We have looked at the proportion of costs borne by customers and taxpayers on one hand and producers on the other under each scenario.

To estimate the difference in resource costs under the two scenarios we have:

- calculated the amount of offshore wind capacity needed to replace the assumed forgone biomass capacity;
- estimated the relative differences in:
 - **generation assets'** capital and operating costs;
 - **transmission assets'** capital and operating costs (including onshore network tariffs and, for offshore wind, local offshore transmission costs); and
 - **reserve generation and back-up generation's** capital and operating costs.
- calculated the net present value of the total relative cost difference and the implied £/MWh cost difference.

Each of these aspects is discussed in greater detail in sections 2 to 7 below.

We also considered whether part of the costs would be borne by producers, resulting in a lower impact on customers. To do this, we considered where these costs would finally be borne, and ran a wholesale market model to assess whether wholesale prices would be lower with more wind on the system. These aspects are discussed in greater detail in section 8 below.

2 Definition of scenarios

We determine the relative cost difference by comparing two scenarios, namely:

- the scenario with biomass conversion (the factual); and
- the scenario with offshore wind (the counterfactual).

Both scenarios are premised on the UK meeting its renewables targets.²

2.1.1 The scenario with biomass conversion

The “with biomass conversion” scenario is equivalent to National Grid’s “Gone Green” scenario from its 2014 “Future Energy Scenarios” document.³ In this scenario, sufficient renewable generation capacity is added to the system to meet GB’s relevant renewable targets at different points in time. We use National Grid’s estimated installed capacity for each technology as part of our modelling in this scenario (Figure 3).

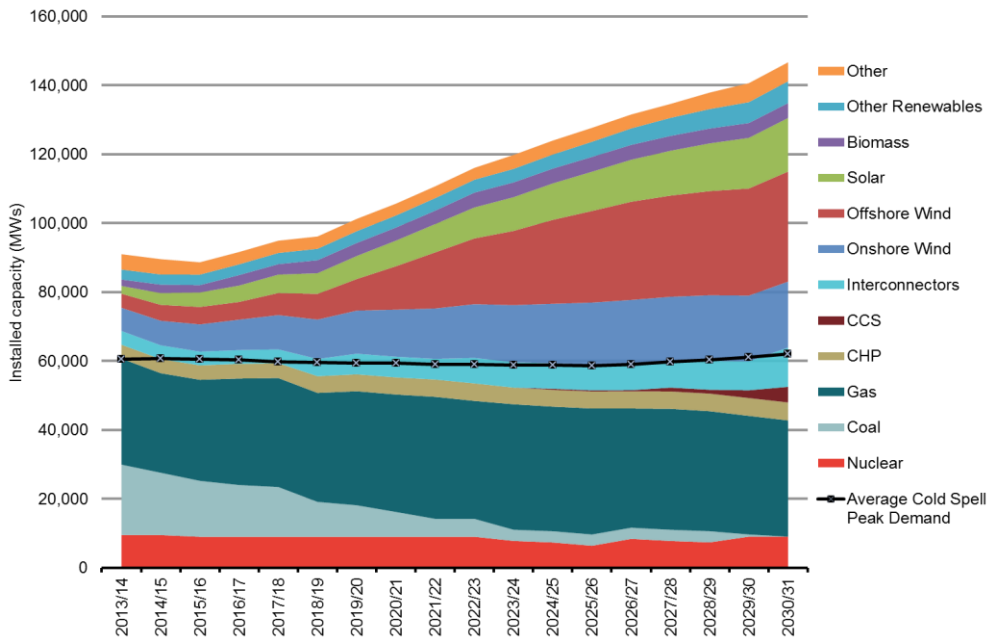
The “Gone Green” scenario includes:

- total biomass capacity of 3,777 MW in 2019/20 and 4,309MW in 2029/30; and
- total offshore wind capacity of 9,146 MW in 2019/20 and 31,075MW in 2029/30.

² The timing of scenarios is dependent on the UK developing sufficient renewables to meet its renewable targets. Should the targets not be met by 2020 and 2030, then there would be more lower-cost projects still available to fulfil the increment of generation which we consider, which would impact on the cost differential. However, to some extent, this is just a function of timing as if the 2020 target is not met, then those projects that would have been required for that will still likely be required in subsequent periods.

³ National Grid, ‘UK Future Energy Scenarios’, 2014.

Figure 3. National Grid's Gone Green scenario's installed capacity



Source: National Grid

Other key statistics from National Grid’s “Gone Green” scenario are summarised in Table 1 below.

Table 1. Key statistics from “Gone Green” scenario

	2013	2020	2030
Electricity			
Peak demand/GW	60	59	62
Annual demand/TWh	345	338	342
Total capacity/GW	91	101	141
Interconnector capacity/GW	4	6	8.4

Source: National Grid

2.1.2 The scenario with offshore wind (the counterfactual)

The counterfactual, which is the scenario with additional offshore wind, is equivalent to the above scenario except that 500 MW less biomass conversion is

Definition of scenarios

commissioned. That is, in this scenario 3,277 MW of biomass conversion is installed by 2019/20 and 3,809 MW is installed by 2029/30.

Instead, an additional increment of offshore wind is commissioned so as to give equivalent average renewables output. We discuss below how the required additional offshore wind capacity is calculated.

2.1.3 Timeframes for scenarios

We consider these scenarios at two points in time, 2020 and 2030. That is, we assume the incremental biomass and offshore wind plants are commissioned in either 2020 or 2030, and then we estimate the net present value of the cost difference over the lifetime of the assets.⁴

⁴ As we are considering the underlying economic costs to society of the different generation methods, we have not specifically considered the likelihood of biomass plants being commissioned in 2020 and 2030. We note, however, the current GB policy settings may reduce this likelihood.

3 How much wind is required to replace biomass?

We have calculated the total offshore wind capacity that would be required to displace the 500 MW of biomass as an input into our estimates of relative generation, transmission, reserve and back-up costs.

To estimate the required additional wind capacity we have:

- estimated the generation output produced by the 500 MW biomass capacity; and
- estimated the amount of offshore wind capacity required to produce that same level of output.

We undertook these calculations using estimated average load factors for both biomass and offshore wind. We have sourced the respective load factors from publicly available sources. The estimated load factors are:

- 38-39%⁵ for offshore wind, which is sourced from DECC's Electricity Generation Costs report.^{6 7}
- 65% for biomass, DECC's Electricity Generation Costs report states an assumed biomass load factor of 65%. This differs from Drax's published results for 2013, which states it has achieved load factors of 75% for its biomass conversion⁸. National Grid⁹ stated that it models biomass conversion plants' load factors on a plant-by-plant basis. Drax's public reports also suggest that higher load factors are technically feasible in the future. On the other hand, the load factor of any incremental biomass, should it be commissioned, will be to some extent the outcome of the level of subsidy it may receive. Without knowledge of future subsidy levels, it is difficult estimate precisely where in the merit order biomass would sit, and therefore what expected load factor it would achieve. On that basis, we have conservatively used DECC's

⁵ More specifically, 38% for Round 2 offshore wind and 39% for Round 3 offshore wind.

⁶ DECC regularly produces estimates of the costs and technical specifications for different generation technologies. DECC's estimates include details on model inputs such as load factors, discount rates, project timings and lifespan, and capital and operating costs.

⁷ To date, offshore wind in the UK has typically achieved lower load factors than this, with average annual load factors over the last ten years ranging from 24% to 38% due, in part, to differing average wind speeds over the period. Source: DECC, (2014), *Digest of United Kingdom energy statistics (DUKES)*, Chapter 6: Renewable sources of energy.

⁸ Drax Group Ltd, Preliminary Results for the year ended 31 December 2013.

⁹ National Grid, "EMR Analytical Report", 2013

65% assumed biomass load factors, although we note that if a higher load factor was used – such as 75% - then the estimated levels of savings from biomass conversion would be larger.

Using these load factors, we estimate that 855 MW of offshore wind would need to be installed in order to produce the equivalent average annual output of 500 MWs of biomass (Table 2).

Table 2. Required incremental wind capacity¹⁰

	Capacity (MW)	Load factor	Output (MWh)
Biomass	500	65%	2,847,000
Offshore wind	855	38%	2,847,000

Source: Frontier Economics

¹⁰ Note these load factors have not been adjusted for losses. If offshore wind in fact incurs greater losses then this would mean the cost savings for biomass conversion are even larger.

4 Generation costs

We have estimated the generation costs for each technology in both time periods.

To do this we have compared the levelised costs for both technologies, assuming the plants were commissioned in either 2020 or 2030. Levelised costs are costs associated with the whole ‘life cycle’ of a plant, and are typically expressed as a £/MWh figure.

The inputs for our levelised cost estimates are sourced from DECC’s Electricity Generation Costs report,¹¹ and we have calibrated our model to produce similar outputs to the DECC model. We have used DECC’s central estimates for the cost inputs, such as development and capital costs, fixed and variable operation and maintenance costs. It is recognised that there is uncertainty as what these costs will be in the future, and we have assumed that DECC’s central estimate is the best estimate for the future given the availability of information at this time.

The major differences between DECC’s model and our model, is that we have excluded connection and system use charges from the levelised cost estimates.

We have excluded these network charges because:

- the basis by which system use charges will be calculated in 2020 and 2030 is likely different than the current method at the time of DECC’s levelised cost report;¹² and
- DECC’s report is based on wider averages where we can be more specific about location/type.

We have estimated system use charges separately below.

Cost estimates for biomass conversion are only provided by DECC as far as 2016. We have assumed constant real biomass generation costs through to 2020 and 2030. This approach seems appropriate as there are fewer ‘learning from doing’ benefits likely to accrue in biomass conversion,¹³ as compared to more nascent and capital intensive technologies such as offshore wind, which are forecast to decrease in costs over time.

For the offshore wind, we assume that lower cost technologies/locations are commissioned first, with higher cost technologies/locations not commissioned until the lower cost options have been fully utilised. To that end, when

¹¹ DECC, “Electricity Generation Costs”, December 2013.

¹² National Grid, “Forecast TNUoS tariffs from 2014/15 to 2018/19”, 2014.

¹³ For instance, DECC’s estimated levelised costs for biomass are constant for plants commissioned 2014 to 2016.

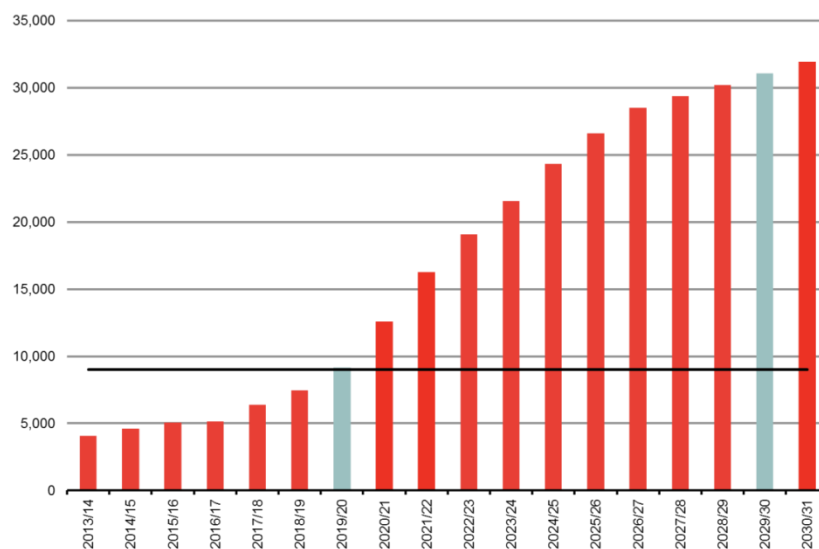
considering the costs of incremental offshore wind that may be deployed instead of biomass, we have estimated the additional capacity's likely:

- technology type – whether it would be Round 2 or Round 3; and
- location – typically generation connecting to the onshore grid further north in GB incurs larger transmission costs¹⁴.

To do this we first considered how much offshore wind capacity needs to be installed to meet the required capacity in the biomass scenario (i.e. National Grid's "Gone Green" scenario) and compared this to the amount of planned capacity from offshore wind projects across the technology types.

The amount of estimated installed offshore wind in the "Gone Green" scenario is shown in Figure 4. The total required offshore wind capacity is 9,146 MW in 2019/20 and 31,075 MW in 2029/30

Figure 4. Estimated offshore wind capacity in 'Gone Green' scenario



Source: National Grid

We then compare this required capacity to the current and potential sites under development. The Crown Estate¹⁵ lists current and planned offshore wind sites, including location and potential capacity of each site.

We summarise the general cost differences between technology and location in Table 3 including potential total capacity of all projects in each category. We note that actual costs will vary on a project-by-project basis, but as we do not

¹⁴ A detailed discussion on transmission costs is included the following section.

¹⁵ The Crown Estate, 2013, "Transmission infrastructure associated with connecting offshore generation".

Generation costs

have cost data to the individual firm level we have assessed relative costs at the average level across technologies and location.

Table 3. Summary of differences between offshore wind technology and location

	Levelised costs 2020 (£/MWh)	Levelised costs 2030 (£/MWh)	Potential capacity (MWs)
Round 1¹⁶ & 2	111	104	9,014
Scottish territorial sites	111	104	4,765
Round 3	119	104	24,555

Source: Frontier Economics

From the above, we can see that even if all the lower cost projects – Round 1 and Round 2 – were commissioned, this would be insufficient to produce the required offshore capacity in the biomass scenario or the offshore wind scenario in 2020 (9,146 MW) or 2030 (31,075 MW).

Therefore, in order to meet the required capacity of offshore wind in 2020 and 2030, we assume that higher cost projects will also need to be commissioned.¹⁷

These higher costs projects are either Scottish territorial sites or Round 3 technology sites. Of these two, Scottish territorial sites would likely be lower cost in 2020 than Round 3 given Round 3's higher generation costs and higher offshore transmission costs.¹⁸ Generation costs for Round 3 projects are predicted to come down over time (Table 3), which might make these projects more viable in 2030 rather than 2020.

For the 2020 scenario, the required offshore wind capacity could be met by adding incremental Scottish territorial sites to the Round 1 and 2 capacity. For 2030, however, Scottish territorial sites would be insufficient to meet the 2030 capacity even if all projects were commissioned by that date.¹⁹

¹⁶ DECC has not included specific Round 1 costs and therefore we have included Round 1 in the Round 2 totals.

¹⁷ Again, this is premised on the UK meeting its renewable targets as planned. Even if the targets are not met on time, then it is still likely that these higher cost locations/technologies will be required at some point in time.

¹⁸ Discussed in more detail below.

¹⁹ In 2030 the required offshore capacity would be 31,075 MW plus the additional 855 MW to replace the forgone 500 MW of biomass, whereas total potential Round 1, Round 2 and Scottish would be 13,779 MW

On that basis, for the incremental offshore wind capacity, we have used cost estimates for:

- Scottish territorial sites for the 2020 time scenario; and
- Round 3 sites for the 2030 time scenario.

The below table shows the difference in generation costs on a £ per MW basis.

Table 4. Generation costs (£/MWh)

£/MW	2020	2030
Offshore wind	111	104
Biomass conversion	105	105
Difference	6	-1

Source: Frontier Economics

To get the difference in generation costs over the life of the assets we calculated the net present value (NPV) of the cost differential. That is, we discounted back the relevant cost cash flows over the 22 year²⁰ period to a present day value.

The levelised cost estimates are calculated by dividing the NPV of total costs by the NPV of all output for the particular technology.

$$\text{Levelised cost of generation} = \frac{\text{NPV of total costs}}{\text{NPV of generation output}}$$

To calculate the NPV of total costs we therefore multiply the levelised costs by the NPV of generation output. We calculate the NPV of generation output by assuming a flat output profile over the life of the asset, and discount using the 10% discount rate used by DECC.²¹

²⁰ DECC's "Electricity Generation Costs" report uses an operating period of 22 years for biomass, which is the time period we use for calculating the NPV.

²¹ DECC, "Electricity Generation Costs", December 2013

Table 5. NPV of difference in generation costs

	2020	2030
Offshore wind	£2,773,000,000	£2,601,000,000
Biomass conversion	£2,612,000,000	£2,612,000,000
Difference	£161,000,000	-£11,000,000

Source: Frontier Economics

The reversal in the 2030 difference in costs is due the effects of learning from doing which, as discussed above, reduce the construction cost of offshore wind over time.

5 Transmission costs

As noted above, we have calculated transmission costs separately to the generation costs. There are two relevant types of transmission that we have considered, namely:

- onshore transmission; and
- offshore transmission costs.

5.1.1 Onshore transmission charges

To estimate the difference in total onshore transmission costs between the biomass scenario and the offshore wind scenario, we have estimated the average Transmission Network Use of System (TNUoS) tariffs for the incremental biomass and offshore wind capacity in each scenario.

TNUoS tariffs are set by National Grid to reflect generators' impact on the transmission network. We have used National Grid's published forecast TNUoS tariffs for 2018/19. This is the furthest year out that National Grid currently forecasts. These forecasts use the newly approved tariff methodology²² which is intended to set tariffs on a cost reflective basis. Therefore, we make the assumption that the incremental tariff costs are a good estimate of the additional costs to society for transmission on the incremental generation in each scenario²³.

Under the new methodology, two factors that impact on the TNUoS tariffs calculations are:

- load factors – part of the tariff is based on an average plant load factor; and
- geographic location of generation – TNUoS tariffs are calculated on the basis of “zones”, or geographic regions throughout GB and, in general, the tariffs increase the further north a generator is located.

In calculating transmission costs, we used the same load factors as for the above generation costs calculations.

For geographic location, it is not possible to forecast exactly where the displaced biomass plants or the additional offshore wind plants would be, as it is unclear exactly which are the marginal investments.

²² As part of Project TransmiT, Ofgem recently approved a change in the approach to setting transmission charges, based on the argument that the so-called “Working-group Alternative Code Modification 2” methodology from CUSC Modification Proposal CMP213 is more cost reflective than the current approach.

²³ We note that non-locational tariff elements will drop out of our analysis as we take the difference between biomass and offshore wind TNUoS costs.

For biomass we calculated potential TNUoS tariffs for the locations of four plants which we consider are potential candidates for biomass conversion - Rugeley, Eggborough, Ratcliffe and Cottam. To be conservative, we then took the highest cost location as our comparator against offshore wind.

For offshore wind, we calculated a weighted average of potential plant locations in order to estimate the average TNUoS tariff. We averaged:

- all Scottish territorial sites under development for the 2020 scenario; and
- all Round 3 zones under development for the 2030 scenario.

For some Round 3 offshore wind sites it is difficult to discern at this point of the projects' development exactly which TNUoS zone they may connect to the network, or they may connect into more than one zone. Whenever there was some ambiguity we conservatively estimated the lower cost tariff zone.

The results are shown below in Table 6, with figures converted into £/kW values.

Table 6. Estimated TNUoS tariffs £/kW of capacity

	2020	2030
Offshore wind	24.18	4.83
Biomass conversion	6.07	6.07
Difference	18.11	1.24

Source: Frontier Economics

TNUoS charges are based on installed capacity. As noted above, to displace 500 MW of biomass conversion capacity would require 855 MW of offshore wind. Therefore, while in 2030 incremental offshore wind TNUoS charges are lower per kW, at an aggregate level the required additional transmission cost for the offshore wind increment is higher than for biomass.

We have calculated the NPV of the TNUoS tariffs based on the above weighted average tariff, the incremental capacity of biomass or offshore wind, the life-time of the asset and the network operator's discount rate.

Transmission costs

Table 7. NPV of onshore network transmission costs

	2020	2030
Offshore wind	£265,000,000	£53,000,000
Biomass conversion	£39,000,000	£39,000,000
Difference	£226,000,000	£14,000,000

Source: Frontier Economics

The smaller 2030 difference in costs is due to Round 3 sites being, on average, further south and therefore having lower tariffs.

5.1.2 Offshore transmission costs

We have also estimated offshore transmission costs. These charges typically form a much larger proportion of offshore wind's transmission costs than do the relevant onshore TNUoS tariffs.

Offshore wind generators tariffs include three components:²⁴

- **Transmission circuits:** to reflect the costs of local onshore and offshore transmission circuits and substations;
- **Substations:** to reflect the costs of local onshore and offshore substations; and
- **Embedded Transmission Use of System (ETUoS):** A tariff to recover an operator's cost of capital where costs have subsequently been passed onto an offshore transmission owner (OFTO) at the point of asset transfer.

²⁴ Guidance Notes for Generator Offshore Local TNUoS Charges Radial Connections, January 2013

Unlike onshore TNUoS tariffs, there is no uniform methodology for calculating local offshore transmission tariffs. That is because local offshore tariffs are dependent on the individualised transmission connections for each project, with charges set to cover the cost of capital over the assets' lifetime and an appropriate return to the owner. The main factors that influence the cost of the local offshore transmission are local geography, distance from coast and network connection and time period when built.

In order to estimate future local offshore transmission charges we can consider current charges for operating offshore wind sites. National Grid publishes offshore local tariffs and ETUoS for various existing generators as shown in Table 8. Current offshore local tariffs (£/kW)^{25 26}

Table 8. Current offshore local tariffs (£/kW)²⁷

Tariff Component (£/kW)				
Generator	Substation	Circuit	ETUoS	Total
Robin Rigg East	-0.404	26.758	8.294	34.648
Robin Rigg West	-0.404	26.758	8.294	34.648
Gunfleet Sands 1 & 2	15.287	14.035	2.623	31.945
Barrow	7.064	36.956	0.918	44.938
Ormonde	21.837	40.680	0.3242	62.840
Walney 1	18.846	37.532	-	56.378
Walney 2	18.709	37.863	-	56.572
Sheringham Shoal	21.124	24.774	0.539	46.436
Greater Gabbard	13.260	30.469	-	43.729
Average				45.177

Source: National Grid

Future offshore projects will face different changes depending on, amongst other things, their distance from shore and the local topography.

²⁵ National Grid, "The Statement of Use of System Charges Effective from 1 April 2014". National Grid states that it will publish further tariff information applicable to generation connected to offshore transmission infrastructure once the tender process relating to the sale of the relating offshore transmission assets has been completed.

²⁶ The onshore local tariffs, if applicable, account for only a small fraction of the offshore local tariffs and ETUoS

²⁷ These current tariffs essentially reflect the average cost of local offshore transmission. There is an argument that for an additional increment of offshore wind, as used in our analysis, a low marginal cost is a more appropriate comparator. This would assume that the economies of scale of building offshore local transmission are such that existing cables may already exist, with spare capacity, for the incremental wind generation to use. However, this typically would require an OFTO or a developer to have taken more risk in relation to the (albeit small) incremental cost of installing a higher capacity connection, which the OFTO regime may not be well designed to facilitate. It is far from clear that this would therefore be the outcome.

Scottish sites are generally located further north than existing offshore wind sites, and may therefore have on average higher local offshore transmission costs than current sites. However, in order to be conservative and to account for possible future reduction in the capital costs of building new local offshore transmission infrastructure, we have used the first quartile²⁸ of the current local offshore transmission charges as the estimate for future Scottish territorial water sites. The first quartile of current tariffs is £35.90 per kW of installed capacity.

Round 3 local offshore transmission costs are likely to be on average higher again as they are on average further from shore and in deeper water.²⁹ Therefore, we have used the third quartile³⁰ of current offshore tariffs as an estimate for incremental Round 3 offshore wind tariffs. Again, we note that this may underestimate future offshore transmission tariffs, but we are adopting this estimate so as to be conservative and to allow for possible future decreases in capital costs. The third quartile of current tariffs is £53.89 per kW of installed capacity.

We can therefore estimate the difference between the biomass scenario (i.e. with no offshore transmission tariff for the incremental capacity) and the offshore wind scenario, and calculate the NPV based on this difference, the incremental capacity of offshore wind, the life-time of the asset and the relevant discount rate for owners of local offshore transmission infrastructure (Table 9).

Table 9. NPV of local offshore transmission costs

	2020	2030
Offshore wind	£313,000,000	£470,000,000
Biomass conversion	£0	£0
Difference	£313,000,000	£470,000,000

Source: Frontier Economics

The difference in costs of local offshore transmission are substantial due to the significant costs associated with building the transmission capacity necessary to connect offshore wind to the onshore transmission network.

²⁸ That is, the middle value between the lowest number and the median number of current offshore transmission charges.

²⁹ See for example, European Wind Energy Association, “The European offshore wind industry – key trends and statistics 2012”, January 2014.

³⁰ That is, the middle value between the median and the highest number of current offshore transmission charges.

6 Operating reserve and back-up

We have also estimated the capital and operating costs of plants required to provide operating reserve and back-up to secure the power system. It is important to be clear as to the difference between these two requirements:

- operating reserves, or system balancing reserves, are the additional costs from the relatively short-term adjustments required to manage output fluctuations over the time period from minutes to hours – these may typically be deployed to manage balancing issues arising from wind forecast error; and
- back-up costs relate to the surplus capacity required to ensure sufficient generation output will be available at times of peak demands when intermittent generation is not operating, even absent forecast error.

In general, offshore wind requires both more back-up generation as it is intermittent and more reserve, as its output is uncertain.³¹

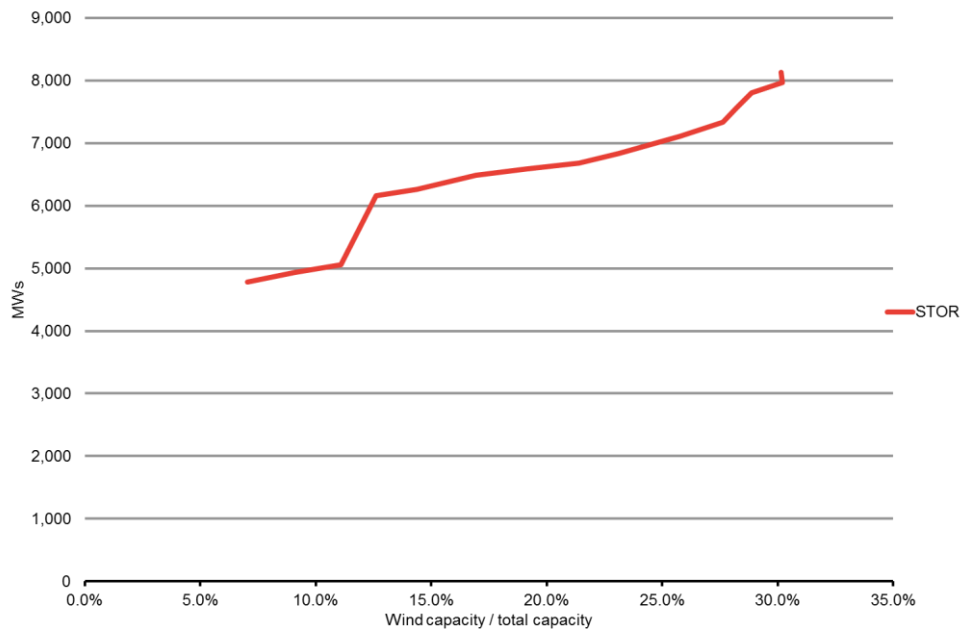
We have separately estimated reserve and back-up costs below.

6.1.1 Operating reserve

The required operating reserve increases as the amount of installed wind increases. Figure 5 shows the estimated increase in total required operating reserve, as a proportion of wind installed (onshore and offshore) on the system, increases from 2011/12 to 2025/26. Without additional wind, National Grid estimates that total operating reserve requirements would be flat from 2014/15 onwards. We can therefore see at an intuitive level that an extra increment of wind capacity would increase reserve cost.

³¹ National Grid, “Operating the Electricity Transmission Networks in 2020”, 2011: “For example, National Grid expects to further improve forecast accuracy of wind generation. Based on analysis of current data from GB and Europe, it is currently assumed that wind output can deviate from forecast by 50% over 4 hours however it is expected that this error could be reduced to around 30% by 2020 through improved wind forecasting models. Currently, the level of uncertainty pertaining to generation and demand can be forecast to a high level of certainty. This stems from an ability to forecast demand to a high level of certainty through a deep understanding of historical and intrinsic behaviours, experiential learning and sophisticated modelling techniques. The ability to forecast patterns of generation comes through economic analysis, knowledge of long term generation performance and a relatively stable demand profile that can be met through controllable and predictable sources of generation.”

Figure 5. Average MWs operating reserve levels by system's proportion of wind capacity



Source: National Grid

To estimate the additional operating reserve costs for the incremental offshore wind we have used National Grid's operating reserves forecasts from its "Operating the Electricity Transmission Networks in 2020" document.³² The total cost estimated for wind in 2020 is £286 million, with an estimated installed capacity of 26,777 MW of wind.³³ These calculations do not differentiate between onshore and offshore wind – although National Grid did use an average load factor of 30% (the lower the load factor the higher the required operating reserve).

We have considered the reserve cost per MW of installed wind over different increments of total installed wind (Figure 6). From this we can see that the £/MW cost increases as the total amount of wind installed increases, but the rate of increase appears to reduce significantly at higher penetrations.

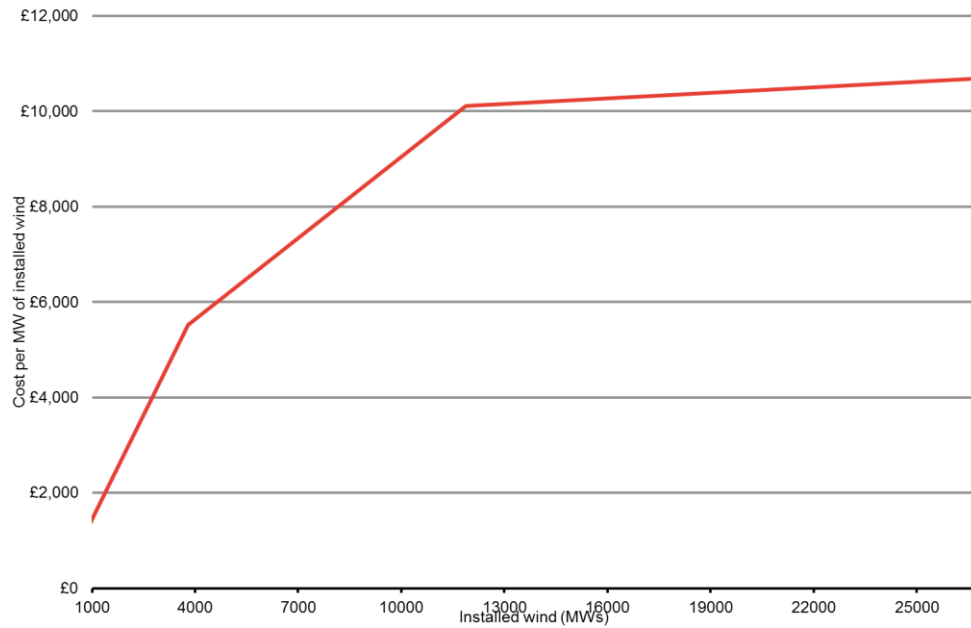
On that basis, we can divide the total costs of operating reserves stemming specifically from wind by the expected wind capacity in 2020 to get a per MW cost - £10,683/MW. It is likely that this is a conservative estimate, as the

³² National Grid, "Operating the Electricity Transmission Networks in 2020", 2011

³³ These estimates do not include any additional response requirements, such as for maintaining system frequency, which may be needed due to increased wind on the system. If these additional costs were included then the cost savings for biomass conversion would be even larger.

additional increment of offshore wind in the counterfactual would likely increase the per MW reserve cost further.

Figure 6. Operating reserve cost of per MW of installed wind



Source: National Grid, "Operating the Electricity Transmission Networks in 2020", 2011

For 2030, this figure is likely to increase further as the total wind capacity (offshore and onshore) is forecast to nearly double from 2020's 26,777 MW of wind to over 50,000 MW.³⁴ However, to be conservative we have used the same 2020 figure of £10,683/MW in the 2030 scenario.

We have calculated the NPV based on this difference, the incremental capacity of offshore wind, the life-time of the asset and DECC's 10% discount rate.

³⁴ National Grid, 'UK Future Energy Scenarios', 2014.

Table 10. NPV of operational reserve costs

	2020	2030
Offshore wind	£80,000,000	£80,000,000
Biomass conversion	£0	£0
Difference	£80,000,000	£80,000,000

Source: Frontier Economics

6.1.2 Back-up generation

Any power system requires an amount of latent capacity to account for unavailability of installed generation and demand variation. Reliance on intermittent generation, such as wind, increases the amount of back-up capacity required as it is less likely than other forms of generation to produce at full output at times of peak demand.

Therefore, in order for the system to retain the same security of supply as it would have in the biomass scenario, additional (dispatchable) capacity would have to be built in the offshore wind scenario so that supply could match demand even in times when the incremental offshore wind sites were not generating.

It should be noted that all generation capacity makes some contribution to security of supply. It is just that offshore wind does not contribute as much, per MW, as other generation sources. In their Electricity Capacity Assessment Report, Ofgem uses a de-rating factor to adjust capacity for its contribution to security of supply. De-rated capacity is the proportion of installed capacity that can be expected to be available at peak demand taking into account the fact that plant are sometimes unavailable due to outages or not operating at full capacity. Table 11 shows the published de-rating factors for biomass and offshore wind.

Table 11. De-rated capacity by technology

Technology	Availability
Biomass	88%
Offshore wind	17% to 24%

Source: National Grid, "Capacity Market Auction Guidelines: 2014 Four year ahead Capacity Market Auction"; Ofgem, "Electricity Capacity Assessment Report 2013".

In order to quantify the difference in back-up costs between the factual and the counterfactual, we assess how much additional back up capacity would be required if 500MW of relatively reliable biomass is removed from the system and replaced with offshore wind.

To undertake this estimate we performed the following steps:

- calculate the capacity credit that will be forgone from the loss of 500 MWs of biomass. That is:

$$500MW \times 88\% = 440 MW$$

- subtract from this the capacity credit³⁵ from the incremental wind.

$$855MW \times 24\% = 205 MW$$

- estimate the cost of the remainder on the basis of an estimate of the capital cost of a best new entrant for a reliable conventional plant³⁶.

$$234MW \times £49,000 = £11.5 \text{ million}$$

We assume this cost applies equivalently to the 2020 and 2030 scenario.

We have calculated the NPV based on this difference, the life-time of the asset and DECC's 10% discount rate.

³⁵ Note to be conservative we have used the higher estimate for wind of 24%.

³⁶ DECC, Cost of new entrant (CONE).

Table 12. NPV of back-up generation costs

	2020	2030
Offshore wind	£101,000,000	£101,000,000
Biomass conversion	£0	£0
Difference	£101,000,000	£101,000,000

Source: Frontier Economics

7 Estimating the total cost to society

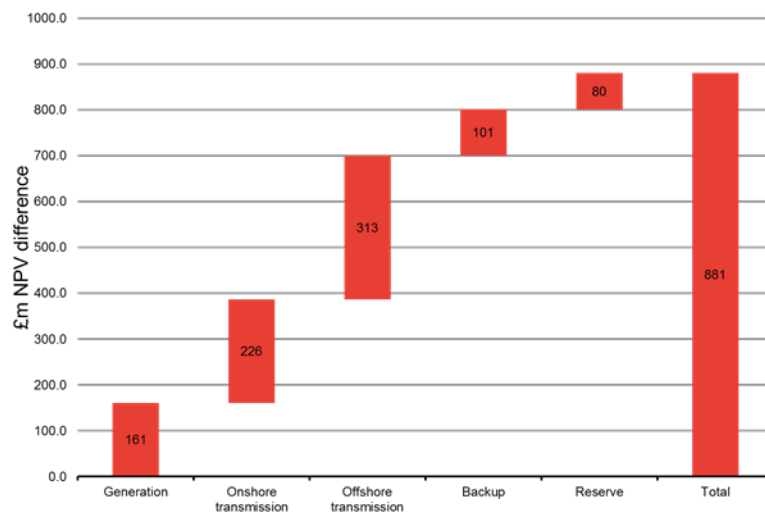
In the preceding sections, we have considered the difference in total system costs of displacing biomass with offshore wind in respect of four cost categories:

- the levelised costs of both technologies;
- the transmission system costs of both (onshore and offshore);
- the reserve costs (e.g. the level of additional capacity required on the system to account for the more uncertain nature of wind generation); and
- the back-up costs (e.g. the amount of generation required to support the additional increment of intermittent wind generation and hence ensure consistent levels of system security).

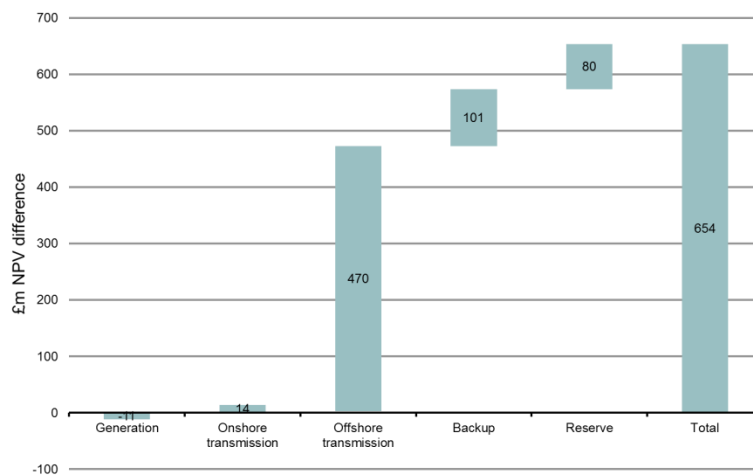
Based on the range of assumptions we are making, in NPV terms over 22 years, replacing biomass with offshore wind would cost an additional approximately £900 million in the 2020 scenario and approximately £650 million in the 2030 scenario.

Figure 7 and Figure 8 below shows a breakdown of the additional costs.

Figure 7. Differences in cost between biomass and offshore wind in 2020



Source: Frontier Economics

Figure 8. Differences in cost between biomass and offshore wind in 2030

Source: Frontier Economics

The figures shows that, based on the range of assumptions we are making, the three key drivers of cost differences are:

- **levelised costs (£-11 million to £161 million):** the upfront capital costs of offshore wind are significantly higher than those of biomass, outweighing the availability of lower cost energy once the windfarms are built;
- **onshore transmission costs (£14 million to £226 million):** We have assumed that biomass conversion would involve existing coal sites and therefore have zero connection costs. Given planned 2020 offshore wind connections, an increment of 855MW of offshore wind would be likely to connect to the onshore grid in Scotland. The onshore transmission cost difference therefore reflects the different transmission system investment costs associated with the respective connection points. We have not taken any account of the marginal increase in operating costs and losses on the network associated with moving transmission from the centre of the UK to Scotland; and
- **offshore transmission costs (£313 million to £470 million):** there are significant costs associated with building the transmission capacity necessary to connect offshore wind to the onshore transmission network.

Transmission costs are clearly a large part of the total difference which we estimate. We have had to make a number of assumptions (which we discuss above) in relation to those costs. In doing so, we have attempted to be

Estimating the total cost to society

conservative. However, we note that even without all transmission cost impacts, offshore wind would be more expensive than biomass conversion by £169 million to £341 million. And while estimating the transmission cost is inevitably difficult as a result of the need to make assumptions, it barely seems credible to suggest that there would be no network-related difference in cost.

8 Estimating the cost to customers

The total social costs calculated in section 7 above could be borne by various groups. In this section we consider how these costs are likely to be distributed and conclude that, ultimately, it will be electricity consumers that bear these costs.

There are broadly three types of direct costs to consider:

- those borne initially by renewables generators, in the form of capital and operating costs;
- those borne by National Grid or OFTOs, covering the costs of system management; and
- those borne by other generators, associated with additional reserve or back-up capacity.

In addition to these, reductions in wholesale prices as a result of the exchange of (higher marginal cost) biomass for (lower marginal cost) wind generation could result in a transfer from existing generators to customers, reducing the total share of the societal cost borne by customers.

We note that there may be other transfers to or from producers which could be considered – the two most relevant may be through the capacity mechanism and constraints. However, we do not take them into account in our quantitative analysis, an approach which we believe is likely to be conservative:

- in relation to capacity mechanism revenues, producers would bear part of the cost to society if the move from biomass to wind (both of which would be outside the capacity mechanism as subsidised plant) would reduce the cost of the marginal unit in the capacity auction. However, it is not clear how or why this would be the case – if anything, as we noted above, more thermal generation would need to be acquired with more wind on the system; and
- in relation to constraints, we note that any major impact would be temporary as it would be likely to trigger new transmission investment (the cost of which we are already taking into account), may be small given the increments of generation being considered, and given biomass conversion would be likely to take place at stations away from major constrained boundaries, would if anything increase costs to customers in the offshore wind scenario.

We discuss below each of the direct cost elements in turn and then consider transfers from producers. In relation to the **costs borne by renewables generators**, the CfD support mechanism is designed to provide developers with just enough support to meet their levelised cost of generation. It is reasonable to

assume that, if a renewables project is developed, then the expected level of support is at least as large as the cost of the project to the generator. If this were not the case, the project would not have been built. Assuming therefore that these subsidy payments are at least large enough to meet the capital and operating costs of any new generation, and given that these costs are borne by consumers through energy bill levies, it is reasonable to assume that these costs are paid for by end consumers.

Offshore transmission costs may initially be borne by the renewables generator or an OFTO. Irrespective, they will eventually be borne by the generator in the form of the various components of offshore transmission charges. As these will form a part of the cost base of the generator, following the same logic as above, it is reasonable to assume these are borne by end customers through energy bill levies.

In relation to **onshore transmission costs**, these are borne principally (73%) directly by customers under National Grid's charging methodology. While 27% of charges are borne by the generality of generators (including the renewable generator in question), in the long run it is reasonable to assume that increases in the onshore transmission cost base are passed through to customers.

The cost of **operating reserve** may initially be incurred by the generators providing it, but can be assumed to be passed on to National Grid. These costs will then largely be recouped through BSUoS and so passed on eventually to customers.

In the case of **back-up capacity**, this may initially be incurred by the generators providing it, but we would expect remuneration for this capital cost to come from the capacity market (and potentially in part from the energy market, depending on expected load factor)³⁷. Energy payments are borne directly by retailers, and the cost of payments under capacity obligations are also passed directly onto retailers. Again, it is therefore reasonable to expect these costs will be borne by customers.

This leaves the potential for transfers from the generality of generators to customers resulting from a potential reduction in the wholesale price of electricity. To understand the impact of our scenarios on the wholesale electricity market, we have undertaken dispatch modelling of the GB energy market in both 2020 and 2030. Specifically, we have run a simple dispatch model of the GB system with National Grid's "Going Green" plant park, and then with an alternate plant park with 500MW less of biomass and 855 MW more of

³⁷ We note that if demand in the capacity auctions increased as a result of the need for more back-up capacity, it may raise the capacity price paid to all producers, resulting in a transfer from consumers to producers. We ignore this factor in our analysis, in order to ensure our assumptions are conservative.

offshore wind capacity. We calibrated the inputs of the initial runs of our model to achieve results broadly consistent with those achieved by National Grid in their modelling of the “Going Green” scenario. We focus on the impact of the change in plant park on the modelled wholesale price. The wholesale price results from this modelling are shown in Table 13 below.

Table 13. Wholesale prices by scenario in 2020 and 2030 (2014 £s)

Year	More biomass conversion	More offshore wind	Difference
2020	62.65	63.01	+0.36
2030	97.30	98.25	+0.95

Source: Frontier Economics

As can be seen above, the modelling suggests that wholesale energy prices are slightly higher in the runs in which biomass conversion capacity is substituted for offshore wind capacity. This result is counter-intuitive, given that wind has lower short-run marginal generation costs than biomass conversion, due primarily to the absence of fuel costs. In practice however, greater intermittent wind generation is likely to result in more volatile wholesale prices, with relatively low prices during windy periods and relatively high prices during still periods. The net effect on the price facing consumers will be influenced by:

- The true profile of offshore wind load factors; and
- The sensitivity of marginal generation costs to variations in intermittent generation.

The results suggest that, given the specified levels of capacity substitution between biomass conversion and offshore wind, any reductions in wholesale prices owing to wind’s lower generation costs are likely to be negligible. We conclude therefore that there are unlikely to be any significant producer/customer transfers due to changes in the wholesale electricity price.

Overall therefore, it seems reasonable to conclude that the vast majority of the costs included in our societal cost estimate will ultimately be transferred to electricity consumers. The distribution among consumers will depend on their cumulative electricity consumption and their exposure to the levy mechanisms used to fund the capacity market and CfDs. However, at a high-level, the 2020 total cost of £900 million and the 2030 total cost of £650m imply costs per UK household of £33 to £25 per household respectively.³⁸

³⁸ Based on household statistics from ONS, Families and Households, 2013.

In conclusion, this analysis implies that even a marginal shift in the make-up of the UK's generation capacity away from biomass conversion and towards offshore wind would measurably increase households' energy costs.

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