PARSONS BRINCKERHOFF

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SMALL-SCALE GENERATION COST UPDATE

Department of Energy and Climate Change

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Final

Small-scale Generation Cost Update

3514055A

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1 SCOPE OF WORK

1.1.1.1 Parsons Brinckerhoff was contracted by the Department of Energy and Climate Change (DECC) in March 2015 to conduct an update of small-scale renewable generation costs. This update relates to the five generation technologies eligible for the Feed-in Tariff (FIT): wind, solar photovoltaic (PV), hydro, anaerobic digestion (AD) and micro combined heat and power (CHP).

1.1.1.2 Data collection was conducted through the use of questionnaires issued to industry contacts, interviews with key stakeholders and literature reviews. The following report details how this data was used to update capital expenditure (Capex) and operating expenditure (Opex) for generation technologies across their capacity bands, as well as other key assumptions. These values will feed into DECC's FIT model as part of the periodic review. The report also discusses industry opinions and suggestions collected throughout the exercise.

1.2 Stakeholder Engagement

1.2.1.1 In order to collect data relating to the capital and operational costs of small-scale renewable technologies, Parsons Brinckerhoff issued a questionnaire via email to a range of consultees. Individual questionnaires were generated for each technology under review, with a separate 'simplified' questionnaire developed for domestic homeowners with solar PV installations.

1.2.1.2 The stakeholder list to which the questionnaires were issued was generated through a combination of DECC and Parsons Brinckerhoff's contact lists. The complete list ensured that the questionnaire would be issued to trade associations, research bodies, developers, manufacturers, consultants and installers across all technologies within the study. Domestic homeowners with solar PV installations were contacted through the University of Sheffield Microgen Database. The covering email requested that consultees complete any relevant questionnaires and forward the responses to a secure, private mailbox within two weeks. Stakeholders were also asked to contact Parsons Brinckerhoff directly if they wanted their responses to remain anonymous or if they were willing to provide further information through telephone interviews.

1.2.1.3 Initially, a limited number of responses were received to the questionnaire due to the short deadline imposed and as a result of this, the deadline was extended for all stakeholders, and additional time was given to specific stakeholders where requested.

1.2.1.4 Responses to the questionnaire were much smaller in number than originally anticipated and as a result of this, additional evidence has been gathered from multiple sources including the Renewable Energy Association (REA) and the Renewable Energy Consumer Code (RECC) in order to substantiate the assumptions made where survey data was sparse. There were more responses for some types and capacities of projects than others. Areas where this was particularly prevalent include:

- Small scale wind (<100kW); and
- Hydro.

1.2.1.5 Responses relating to solar PV projects were particularly low, with survey responses received from domestic homeowners only. As a result of this, additional data was provided by the Renewable Energy Association (REA) and Renewable Energy

Consumer Code (RECC), which was used to augment the questionnaire data received and guide assumptions for the higher category bands.

1.2.1.6 Where data received was unclear or was not in line with other data within the same technology or capacity band, Parsons Brinckerhoff attempted to contact the questionnaire respondent to cross-check data. Parsons Brinckerhoff also undertook telephone interviews with a number of stakeholders to discuss wider issues across the small-scale generation industry.

1.3 Confidence

1.3.1.1 Within each technology input section below, Parsons Brinckerhoff have provided a table outlining the number of survey responses and sources of cost data received for each capacity band across each technology type. A traffic light-style system has been utilised to show Parsons Brinckerhoff's confidence in the data received as follows:

	Low confidence
	Mid-level confidence
	High confidence

1.3.1.2 When deciding confidence, Parsons Brinckerhoff has considered whether the amount of project data in each capacity band is sufficient to represent the number of active installations across the country, and whether the questionnaire data collected is truly representative of the characteristics seen in operational projects of that type.

1.4 Data Adjustment

1.4.1.1 All cost recommendations given within this report are 'real', which have been generated using a 2014 base year. Any inflation calculations performed are based on the Retail Price Index (RPI).

1.4.1.2 Load factor numbers given are net of availability and take account of non-availability of the generating plant.

1.4.1.3 All costs for domestic systems are inclusive of VAT. All costs quoted for commercial and utility scale installations are exclusive of VAT.

1.5 Consistency

1.5.1.1 In parallel to the work completed by Parsons Brinckerhoff, Arup have completed an exercise updating the costs for large-scale renewables. In order to maintain consistency between the work completed across both projects, Parsons Brinckerhoff approached Arup prior to the questionnaire being issued to agree definitions for Capex and Opex, what the cost figures provided for these items should include and what additional cost figures should be provided by stakeholders completing the questionnaire.

1.5.1.2 The questionnaire defined the following terms:

- 'Capex': should include the design, procurement and construction (EPC) costs, equipment costs and civil works costs. It should NOT include owner's costs, grid connection costs or substation and/or transformer costs.

- 'Opex': should include labour, planned maintenance and lifecycle replacement costs. It should NOT include land costs, property and business rates tax costs, rental and community benefit payments. Variable Opex may also include water and/or chemical usage. Opex costs do not include feedstock or digestate disposal costs for AD.

1.5.1.3 Consultees were asked for costs relating to land purchase or rental, grid connection, connection use of system charges and gate fees, feedstock costs and digestate disposal costs (for AD technologies) as separate items, in keeping with the agreed approach with Arup.

1.5.1.4 NERA Economic Consulting has also undertaken a review of hurdle rates for all large-scale technologies over the same period of data collection. While both Parsons Brinckerhoff and NERA agreed that the hurdle rates for small scale FIT projects would be expected to be different to the ones for large scale projects, given that the risks and the policy support and policy risks that inform investors hurdle rates will be substantially different across the difference sizes of technology, Parsons Brinckerhoff has reviewed the interim assumptions generated by NERA against those generated as part of the following study as part of a sense-check exercise. As the NERA results were not finalised at the time of this report, no numbers can be presented at this stage.

1.5.1.5 All work completed by Parsons Brinkerhoff has undergone a full peer review exercise by Ricardo-AEA and by DECC's internal teams.

2 TECHNOLOGY INPUTS

2.1 Approach and Methodology

2.1.1.1 The survey data received was cleaned and Capex values were adjusted to 2014 values based on the Retail Price Index (RPI).

2.1.1.2 The raw data inputs provided on Capex and Opex have been weighted to provide a more accurate representation of the data; the weighting criteria are detailed below and are provided in Annex A:

- Year Installed (Y): The costs are weighted to reflect the higher costs faced by projects in previous years. The value of the weighting has been established according to the Feed-in Tariff level at the time of installation.
- Data Source (IT): The weighting has been adapted to reflect the investor type on each project. The intention is to adjust for potential bias from different investor types; the values have been predicted to the best estimate.
- Project Type (E): The weighting for this section is to adjust data upwards or downwards where the data provided does not relate to an existing operational project. the adjustment is based on Parsons Brinckerhoff's view on how realistic the estimated pricing is.

2.1.1.3 Based on the weighted Capex and Opex values calculated above for each capacity band, a median value was determined. From this median value a 75% variation either side of the value was calculated and any values outside of this range were considered to be an outlier. Subsequently, a revised median was calculated excluding the outliers.

2.1.1.4 Confidence assumptions have been assigned based on Parsons Brinckerhoff's view based on the approach detailed in Section 1.3. This is largely based on how many responses were received for each band and if these results looked realistic in Parsons Brinckerhoff's experience. One standard deviation of the data set excluding outliers either side of the median was used to establish a high case and low case.

2.1.1.5 This section describes the revisions we have made to the input cost and technology data used in the FIT model. Following discussion with DECC, we reviewed data for those technologies that are currently eligible for the FIT. For those technologies, we have revisited the range of assumptions, including:

- Average installation size;
- The export fraction, or the percentage of the output of a typical installation that would be sold back to the national electricity grid, rather than being used onsite;
- Capital costs for a typical installation within each capacity band, both current and projected;
- Operating costs for a typical installation within each capacity band, both current and projected;
- Load factors;
- The expected lifetime of the technology;
- Hurdle rates; and

- The technical potential of the technology. This is a theoretical maximum, and is very unlikely to be approached or achieved in practice. It is however used within the model as a key input for uptake and supply chain development.

2.1.1.6 A range of different sources have been used to develop the revised assumptions data. These sources are listed in Annex A. In general, our approach has been to combine data from industry discussions with recent independent reports and our own project experience to derive updated values. The majority of the data was collected during April 2015.

2.1.1.7 Part of the scope of our work has been to provide future cost projections to 2021. While we have sought to provide reasonable estimates based on possible future technology, market developments and published predictions, such estimates are by nature uncertain.

2.1.1.8 Capital costs, operating costs and load factors have been derived with Low, Medium and High cases. The Medium case values are based on the median of the data, i.e. the middle value when data is organised in ascending size order. The Medium case value is not the mean of the Low and High case values, although in some cases it may result in a value close to the mean. The Low and High cases are based on the standard deviation of the raw data received, plus our own experience and judgement as to what values would be reasonable.

2.1.1.9 Where box and whisker plots are presented, these have been generated based on questionnaire responses **only** and do not necessarily represent the final assumptions generated.

2.1.2 Definitions

2.1.2.1 Throughout this report, a number of terms have been used and these are defined below:

- **New Build:** where solar PV panels are installed as part of the construction of a building;
- **Retrofit:** where solar PV panels are installed on an existing building;
- **Aggregator**: an organisation that develops/owns a large number of small projects that are treated as individual schemes under the FIT;
- **Building integrated PV**: where photovoltaic materials have been used to replace conventional building materials in a structure (e.g. roof, skylights);
- **Rural:** projects that are in open and exposed areas which are largely free of obstacles in all directions;
- **Urban:** projects within built-up areas, likely to be quite close to buildings and other ground features;
- **Export Fraction:** the average annual fraction of electricity generated by the project and exported to the grid;
- **Hurdle Rate:** the minimum expected project Internal Rate of Return (IRR) for investment in a generation asset realised over the life of the asset, at which investors will make a decision to proceed with the investment;
- **Gearing:** the proportion of debt in the project's capital structure;

- **Effective tax rate:** the implied tax rate on a project after accounting for the debt interest tax shield (if relevant) and capital allowances; and
- **Payback time:** the length of time that the project takes to pay for itself through savings on electricity/energy bills and income from the FIT.

2.1.3 Hurdle Rates

2.1.3.1 Across all technologies, hurdle rates were sought for three types of investors – domestic, commercial and developer/utility. These were defined as follows:

- **Domestic** projects being up to 10kW in size for solar PV installations, 15kW for wind installations and 15kW for hydropower installations that will be installed in, on or near domestic residences;
- **Commercial** projects being those that are built and financed by companies and organisations on their own land, for example, organisations installing solar panels on their roofs, companies installing a wind turbine (or wind turbines) on their site (which could include farmers financing the construction of wind turbines on their fields) and companies installing hydro projects on their land; and
- **Developer** projects built by specialist renewable energy companies that will often pay companies and organisations a rental fee for installing the wind turbine, solar panels or hydro plant on their land. Developer-led projects include those built by utilities.

2.1.3.2 Two different questionnaires were produced in order to gather information on solar PV installations – one that was issued to installers, manufacturers and developers, and a second that was issued to homeowners who had had, or were planning to have, a solar PV installation installed. These domestic questionnaires were developed in such a way so that the domestic questionnaire was much easier to answer for those with limited knowledge of their installation. All questionnaires are included in Annex B. As such, the hurdle rates of domestic-scale solar PV installations were calculated using an alternative methodology outlined below.

2.1.3.3 For AD, wind and hydro technology assumptions, hurdle rates have been calculated by Ricardo-AEA based on questionnaire data gathered by Parsons Brinckerhoff. Survey respondents were asked what their hurdle rate was, and the questionnaire made it clear that the preference was to receive responses regarding minimum required project Internal Rate of Return (IRR) in pre-tax, real terms; however no respondents gave an indication as to the type of hurdle rate that was quoted. As a result Ricardo-AEA made the assumption that most survey responses had been provided in post-tax, nominal terms, which are most commonly used in the industry. To determine the real pre-tax IRR, the formula below was used. The nominal pre-tax IRR is calculated before real pre-tax IRR, as tax is paid on nominal profits; to calculate this, discounted Effective Tax Rates (ETR) were used from KPMG's report "Electricity Market Reform: Review of effective tax rates for renewable technologies" (July 2013).

$$IRR = (1+ \text{Pre-tax nominal IRR with effective discount tax rate}) / (1+\text{inflation}) - 1$$

2.1.3.4 Some respondents also provided gearing rates, interest rates and required equity returns. It was then assumed that the equity returns were nominal returns, and Ricardo-AEA used a second formula, below, as another approach to calculate the pre-tax real IRRs based on this information.

$$IRR = [1 + (\text{gearing} \times \text{interest rate}) + ((1-\text{gearing})*\text{equity return}) / (1 - ETR)] / (1 + \text{inflation}) - 1$$

2.1.3.5 The two metrics were then compared to determine an appropriate pre-tax real IRR to be used.

2.1.3.6 For the solar PV technology assumptions, suitable data for the calculation of hurdle rates was only made available from seven domestic solar installations, and no commercial or developer-led financial information was obtained. Hurdle rates for domestic installations were calculated in a two-part process, where responses to the question “*What is the maximum payback time you would be willing to accept for this installation (years)?*” were used to calculate a minimum required post-tax nominal return, by generating an estimated net cash flow for 30 years in order to calculate a suitable real IRR assumption. Ricardo-AEA also used responses to other questions on installation and running costs, as well as on electricity bill savings, in order to estimate returns for existing projects – they then used these as a sense-check to confirm the results of the first calculation.

2.1.3.7 Suitable hurdle rates for commercial and developer/utility-scale installations were subsequently calculated based on the assumption that commercial investors may also invest for reasons apart from financial return, although rates higher than domestic investors are proposed. Developers will focus on returns, but with competitively priced finance (e.g. debt for 70% of the project at 6% interest and equity returns at 8.5%) real hurdle rates as low as 4% could arise.

2.2 Solar PV

2.2.1 Data Collection

2.2.1.1 Questionnaire responses from members of the solar PV industry were limited in number and as such, the final assumptions presented have been based on a blend of questionnaire responses, data from operational projects gathered by Parsons Brinckerhoff, literature reviews and in-company expertise. Additional data relating to solar PV system costs for installations <16kW was provided by the Renewable Energy Consumer Code (RECC)[1] and this data has been used to guide the Capex costs in the lower capacity bands. A variation of the questionnaire was also issued to domestic homeowners with solar PV installations and their responses have also been used to guide the lower capacity bands. The distribution of data received is as follows:

Capacity bands	<4kW	4-10kW	10-50kW	50-150kW	150-250kW	250-5000kW	Agg <4kW	Agg >4kW	Standalone
Responses/project examples	11 (+5322 RECC)	0 (+1520 RECC)	7 (+59 RECC)	2 (+2 examples)	2 (+2 examples)	14	0	0	15

2.2.1.2 For solar PV installations registered under the FITs scheme, information on the capital and operating/maintenance costs has been updated to reflect recent price data. Other adjustments have been made, including changes to load factors, export fractions and average installation size.

2.2.1.3 Details of how inputs to the model have been derived are provided below.

2.2.2 Average Installation Size

2.2.2.1 The size of a typical installation within each band has been based on the mean size of installations within each capacity band registered for FITs to date using data provided by Ofgem[2]. The assumptions generated are as follows:

Capacity Band	Average installation size (kW)
<4kW new build	3.06
<4kW retrofit	3.06
4 - 10kW new build	8.21
4 - 10kW retrofit	8.21
10 - 50kW new build	33.27
10 - 50kW retrofit	33.27
50-150kW new build	101.86
50-150kW retrofit	101.86
150-250kW new build	211.21
150-250kW retrofit	211.21
250-5000kW new build	1228.75

[1] RECC data is based on actual, reported costs charged by businesses operating in the sector.
[2] Feed-in Tariff Installation Report (31 March 2015), Ofgem. Available: https://www.ofgem.gov.uk/publications-and-updates/feed-tariff-installation-report-31-march-2015

Capacity Band	Average installation size (kW)
250-5000kW retrofit	1228.75
Stand alone	942.78
Aggregator <4kW	2.8
Aggregator >4kW	6

2.2.3 Export Fraction

2.2.3.1 A central case was estimated for export fractions across all capacity bands using the average value of the data received and we have applied an export fraction that is higher than the value in the previous assumptions at 53%, in comparison to the 50% given in the 2012 report. This assumption was largely based on data from domestic systems which had export fractions ranging from 33 – 80%.

2.2.3.2 Stand-alone systems, by definition, export 100% of their generation and this value has been included in the assumptions as a separate line item.

2.2.4 Capex

2.2.4.1 Following peer review by Ricardo-AEA and discussion with DECC, it was decided that the Capex for solar installations <4kW should be based on the responses received for systems installed in 2014 and 2015 only, given the variations in project costs prior to 2014. Given the small number of responses relating to solar PV installations, RECC were also approached and provided a quantity of data relating to the full contract value of solar PV systems (0-16kW) installed between November 2014 and April 2015.

2.2.4.2 Parsons Brinckerhoff compared the data provided by RECC with the assumptions generated through questionnaire responses below and the results are as follows:

Capacity Band	Average	RECC data (£/kWp)	PB's assumptions (£/kWp)
<4 kW	Median	1712.1	1513.7
	Mean	1847.5	1570.6
4-10kW	Median	1450.3	1339 (derived from data bands either side)
	Mean	1530.6	
>10 – 15.9kW	Median	1250.0	1084.9
	Mean	1264.5	1094.3

2.2.4.3 Across all bands, the assumptions generated through questionnaire responses alone are lower. While the questionnaire data gathered for the 10-50kW band were weighted to reflect potential developer gaming, the domestic figures from 2014 and 2015 were not weighted or adjusted. The <4kW value was derived from 5 projects which may potentially have been projects sitting at the lower end of the price spectrum. No questionnaire data was received relating to the 4-10kW band and, as such, the assumption was derived using capacity bands either side of the band Given the sheer quantity of data provided by RECC, it was decided that these data points should be included within the analysis and should shape the cost assumptions for these bands.

2.2.4.4 Capex prices recorded through questionnaire responses only were split as per the existing capacity bands and weightings were applied to each number to adjust them based on Parsons Brinckerhoff's confidence. This data was then combined with that provided by RECC and the median value was found for each group with this value making the 'central case'. 24% either side of the central case value forms the low and high cases, which is based on a combination of the standard deviation of the raw data we received through questionnaire responses and from our in-house experience.

2.2.4.5 No survey data points were available for 4-10kW band and as such, the cost assumption for this band was generated through the use of RECC data.

2.2.4.6 As no projects were specifically given as 'standalone' projects, all ground-mounted plants with an export fraction of 100% were considered to be 'standalone' for the purposes of calculating average installation size and Capex.

2.2.4.7 No data on aggregator systems was provided. Parsons Brinckerhoff has used the assumptions generated in 2012 to estimate low, central and high cases for these systems, with 90% of the cost of the '<4kW' band and '4-10kW' band used to calculate the 'aggregator <4kW' band and 'aggregator >4kW' band respectively.

2.2.4.8 One standard deviation of the entire data set was calculated and this was used to determine the low and high cases of the data as being ±24% either side of the central case. The assumptions generated are as follows:

Capacity Band	Capex (£/kW)		
	Low Case	Central Case	High Case
<4kW new build	1,283	1,688	2,093
<4kW retrofit	1,283	1,688	2,093
4 - 10kW new build	1,096	1,442	1,788
4 - 10kW retrofit	1,096	1,442	1,788
10 - 50kW new build	950	1,250	1,550
10 - 50kW retrofit	950	1,250	1,550
50-150kW new build	892	1,173	1,455
50-150kW retrofit	891	1,173	1,455
150-250kW new build	814	1,072	1,329
150-250kW retrofit	814	1,072	1,329
250-5000kW new build	776	1,021	1,267
250-5000kW retrofit	776	1,021	1,267
Stand alone	790	1,039	1,288
Aggregator <4kW	1,154	1,519	1,883
Aggregator >4kW	986	1,298	1,609

2.2.4.9 Figure 2:1 below shows the distribution of the data received across each capacity band. The data shows that increasing system sizes generally suggest a lower Capex cost per kW installed with decreasing uncertainty around the numbers with increasing capacity.

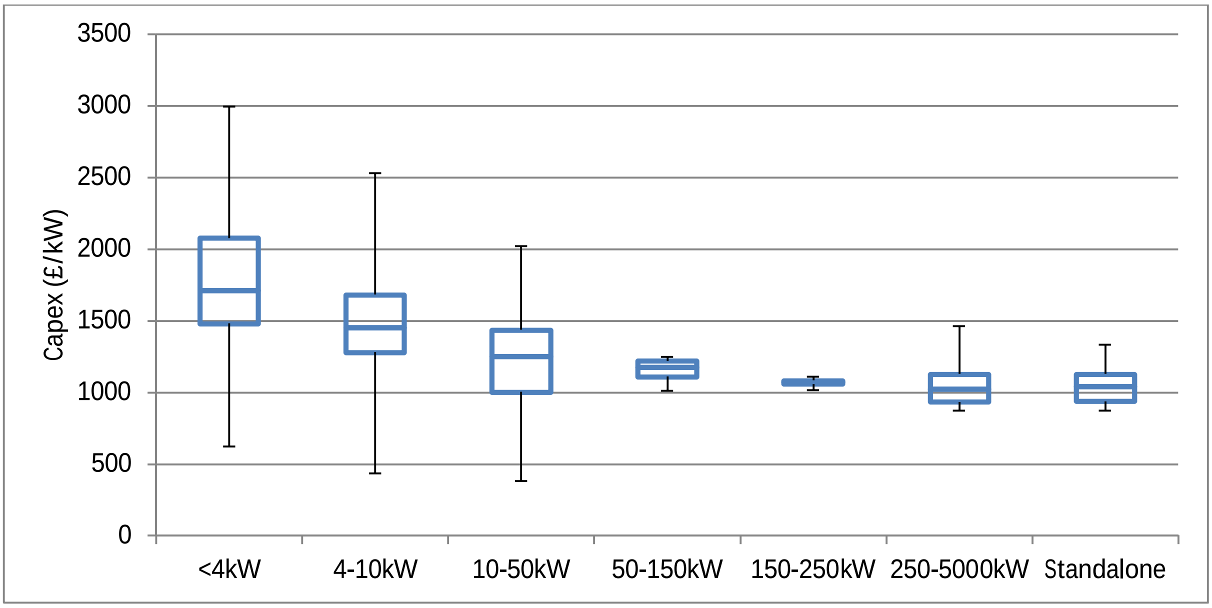

Figure 2:1 Capex data per capacity band (Solar PV) from questionnaire responses

Please note: *the data presented in Figure 2:1 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.*

2.2.5 Forecasting Capex

2.2.5.1 Parsons Brinckerhoff used the IEA Technology Roadmap for PV (2014)[3] report to forecast Capex figures, which indicates that the panel price will decrease by 50% between 2015 and 2035. Capex costs were split into 'panel costs' and 'balance of plant costs' and panel costs were adjusted year-on-year using the IEA figure. The remaining balance of plant costs were adjusted by 2% from 2015 - 2019 in a linear fashion, based on improved installation methods and cheaper system components, but higher labour rates. The overall cost reduction between 2015 and 2021 is 8%.

2.2.5.2 The 2014 IRENA Renewable Power Generation report[4] demonstrates that the decrease in panel prices has been largely linear since May 2012 and as such, a linear decrease in prices has been assumed within Parsons Brinckerhoff's model.

2.2.5.3 A scenario exploring the potential effect on Capex costs if anti-dumping measures were to be relaxed is outlined in section 3.6.

2.2.6 Opex

2.2.6.1 A very limited number of responses were received in relation to Opex costs for solar PV installations, and these were as follows:

[3] Technology Roadmap Solar Photovoltaic Energy 2014 Editions, IEA, IRENA. Available at https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf
[4] Renewable Power Generation Costs in 2014, IRENA. Available at http://www.irena.org/DocumentDownloads/Publications/IRENA_RE_Power_Costs_2014_report.pdf

Capacity bands	<4kW	4-10kW	10-50kW	50-150kW	150-250kW	250-5000kW
Responses/project examples	5	0	1	0	3	12

2.2.6.2 All domestic responses said Opex costs were £0 per year which matches literature reviews. Parsons Brinckerhoff has assumed that the system will require an inverter replacement every 10 years (estimated at £1000 for <4kW and £1200 for 4-10kW) and as such has calculated Opex costs for <4kW and 4-10kW based on this figure.

2.2.6.3 One data point was collected for 10-50kW, assuming an unmonitored system. Inverter replacement was estimated at £3000 every 10 years.

2.2.6.4 No data points were received for 50-150kW. This was estimated using the median of the two central cases either side of the band.

2.2.6.5 Example projects gave estimated Opex figures for 150-250kW which Parsons Brinckerhoff believe had a 50% certainty value, and were large overestimates of true Opex costs. A 50% weighting was applied to these figures and they were also weighted further as per the tables in Annex A.

2.2.6.6 Given the large number of data points for 250kW-5MW, the median value of the weighted figures was taken as the central case, with 20% calculated either side for high and low values. These costs are typically higher as larger systems are often remotely monitored by a number of companies responsible for security and electricity production.

2.2.6.7 As no projects were specifically given as 'standalone' projects, all ground-mounted plants were considered to be 'standalone' for the purposes of calculating Opex.

2.2.6.8 No data on aggregator systems was provided. Parsons Brinckerhoff has used the assumptions generated in 2012 to estimate low, central and high cases for these systems, with 90% of the cost of the '<4kW' band and '4-10kW' band used to calculate the 'aggregator '<4kW' band and 'aggregator '>4kW' band respectively.

2.2.6.9 Due to the lack of data other than 250kW – 5MW, a ±20% range was used to provide the low and high cases for the other capacity bands. The final assumptions generated are as follows:

Capacity Band	Opex (£/kW/year)		
	Low Case	Central Case	High Case
<4kW new build	26.2	32.7	39.2
<4kW retrofit	26.2	32.7	39.2
4 - 10kW new build	11.7	14.6	17.5
4 - 10kW retrofit	11.7	14.6	17.5
10 - 50kW new build	7.3	9.1	10.9
10 - 50kW retrofit	7.3	9.1	10.9
50-150kW new build	7.0	8.7	10.4
50-150kW retrofit	7.0	8.7	10.4
150-250kW new build	6.6	8.3	10.0
150-250kW retrofit	6.6	8.3	10.0

250-5000kW new build	7.6	9.5	11.4
250-5000kW retrofit	7.6	9.5	11.4
Stand alone	7.6	9.5	11.4
Aggregator <4kW	23.5	29.4	35.3
Aggregator >4kW	10.5	13.1	15.8

2.2.7 Forecasting Opex

2.2.7.1 Opex costs have been forecast as reducing in a linear fashion and are split into two types of degression (<4kW, 4-5000kW) based on in-house expertise and understanding of the market. It is unlikely that operation costs will change much and this annual decrease reflects cheaper replacement parts and increasing use of unmanned monitoring stations, with >50kW reaching a plateau around 2021 once larger systems approach, or reach, grid parity.

2.2.7.2 These forecasts are as follows:

Capacity Band	2015	2016	2017	2018	2019	2020	2021
<4kW	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%
4-50kW	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
>50kW	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0%

2.2.8 Load factors

2.2.8.1 A limited number of responses were received in relation to load factors for operational projects, and these were as follows:

Geographical region	South East	South West	Wales	Midlands	Scotland
Responses/project examples	11	5	3	4	2

2.2.8.2 A central case for the South East was calculated using the median of the questionnaire values received. Given that more survey responses were provided for the South East than any other geographical region, the South East value was then adjusted using the weightings below to provide central case values for other regions. This was achieved by applying the irradiance ratio from PVGIS to the South East load factor value.

Geographical region	Irradiance (kWh/m^2)	Relative to London
SE (London)	1300	1
SW (Exeter)	1320	1.02
Midlands (Rugby)	1280	0.98
North (Leeds)	1180	0.91
Wales (Llangurig)	1080	0.83

Scotland (Glasgow)	1100	0.85

Source: PVGIS (CM-SAF)[5]

2.2.8.3 Low and High cases were calculated using an interquartile range of the South East data set received through questionnaire responses either side of the central case value, which equated to ±0.6% of the central case.

2.2.8.4 Final load factor assumptions based on regional averages are as follows:

Region	Load Factor (%)		
	Low Case	**Central Case**	**High Case**
Scotland	8.4%	8.9%	9.5%
Midlands	9.7%	10.3%	10.9%
South East	**9.9%**	**10.5%**	**11.1%**
South West	10.1%	10.7%	11.3%
North	9.0%	9.6%	10.2%
Wales	8.1%	8.7%	9.3%

2.2.8.5 The load factor analysis above is based on a limited number of data points and on PVGIS irradiance data which has limitations[6]. Both of these variables are applied at a regional level and as such, load factors at specific project locations may vary. Parsons Brinckerhoff acknowledges that load factors for PV installations could be refined further using other analytical methodologies should additional robust data be sourced.

2.2.9 Expected lifetime

2.2.10 The typical lifetime for PV systems has been decreased compared to the previous model (from 35 to 30 years) to reflect the realistic lifetime of PV panels as witnessed within recent projects completed by Parsons Brinckerhoff. Note that inverter replacement is included within the operating costs – we have considered that the inverter represents a small enough proportion of the overall capital cost for its replacement to be considered an operating cost.

2.2.11 Hurdle rates

2.2.11.1 The table below details the hurdle rates for solar PV calculated by Ricardo-AEA using the methodology given in section 2.1.3.

[5] PVGIS (Photovoltaic Geographical Information System) data available at http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php

[6] Thomas Huld, Richard Müller, Attilio Gambardella, A new solar radiation database for estimating PV performance in Europe and Africa, Solar Energy, Volume 86, Issue 6, June 2012, Pages 1803-1815.

		Hurdle Rate (%)		
		Low	Medium	High
Domestic, small	Min	0.5%	2.5%	4.5%
	Max	8.0%	10.0%	12.0%
	Avg	**4.2%**	**6.2%**	**8.2%**
Commercial developer, medium	Min	2.0%	4.0%	6.0%
	Max	9.0%	11.0%	13.0%
	Avg	**5.0%**	**7.0%**	**9.0%**
Utility, large	Min	3.0%	5.0%	7.0%
	Max	9.0%	11.0%	13.0%
	Avg	**5.0%**	**7.0%**	**9.0%**

2.2.11.2 The hurdle rates provided by Ricardo-AEA are comparable to the interim results generated by NERA, although the range of the Ricardo-AEA data is slightly larger.

2.2.12 Technical Potential

2.2.12.1 For domestic technical potential, Parsons Brinckerhoff determined the total number of households in the UK using Office for National Statistics figures[7]. 38% of these buildings were discounted due to being 'inappropriate' buildings such as flats (ie. apartments) or listed buildings. The average domestic building size in m^2 and an associated roof area for these buildings was calculated. It was estimated by Parsons Brinckerhoff that 40% of appropriate buildings have a pitched roof area that pointed south (or south-east or south-west).

2.2.12.2 Parsons Brinckerhoff determined that the average domestic property could install a 3.5kWp system.

2.2.12.3 For commercial technical potential, an area of 2,500 million m^2 was assumed for south facing commercial roofs (based on Kingspan Energy – Cutting Costs: The Energy Potential of UK Commercial Rooftops[8]). Of this 70% were assumed to be pitched roofs resulting in 1,750million m^2 available. A further 30% was removed from the area for edging and roof obstacles, giving an availability of 1,225million m^2. This figure was divided by a standard module size of 1.65m^2 and multiplied by the wattage of the module to get the potential output.

2.2.12.4 The remaining 30% of available roof space is assumed to be flat (750million m2). A figure of 2ha per MW was used for row spacing, with a following 30% removed for edging and obstacles.

2.2.12.5 For ground-mounted technical potential, the Agriculture in the United Kingdom[9] report was used to give an estimate of available farm land. 10% of this was deemed to be

[7] Office for National Statistics, 10 December 2013. http://www.ons.gov.uk/ons/rel/family-demography/families-and-households/2013/info-uk-households.html
[8] Cutting Costs: The Energy Potential of UK Commercial Rooftops, 2014. Kingspan Energy. Available at: http://www.interfacecutthefluff.com/wp-content/uploads/2012/09/Kingspan-Energy-CUTTING-COSTS-THE-ENERGY-POTENTIAL-OF-UK-COMMERCIAL-ROOFTOPS.pdf
[9] Agriculture in the United Kingdom, DEFRA, 2014. Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/430411/auk-2014-28may15a.pdf

suitable for solar PV installation (based on estimates of land topography, shading). An assumed install of 2.5ha/MWp was used to calculate the total available capacity.

2.2.12.6 Parsons Brinckerhoff used a database from the European Joint Research Centre (JRC), which uses 11 years of satellite weather data from the 1998 to mid-2010. This database provided values for solar irradiation, temperature, wind speed and barometric pressure for Sheffield; which subsequently provides a specific annual generation (896kWh/kWp) specific to the area. When the potential deployment figure (in kWp) is multiplied by this, an annual generation figure is calculated. There is an MCS requirement to provide a SAP (Standard Assessment Procedure) figure in quotations for solar PV systems. In the earlier versions of the SAP calculator there was only one location used to determine generation, which was Sheffield. This was used as it was a central point for the UK and will provide a most rounded figure for the standard. .While the geometric centre of PV deployment is closer to Birmingham, this method has been used to maintain consistency and as the solar potential established considers the entire UK, it is a fair assumption to use this location.

2.2.12.7 The calculated technical potential for domestic properties was distributed across the <4kW and aggregate <4kW bands; for commercial properties across the 4-10kW, 10-50kW and aggregate >4kW bands; and for available land across the 50-150kW, 150-250kW, 250-5000kW and standalone bands. This distribution was in line with that given by CEPA in the 2012 reports. While some smaller systems may be installed as ground mounted or on commercial properties, some domestic properties may also install larger systems and so the distribution balances across the capacity bands.

Capacity Band	Technical Potential (GWh)				
	Total	Domestic	Commercial	Developer	Utility
<4kW new build	223	212	11	0	0
<4kW retrofit	19,201	18,241	960	0	0
4 - 10kW new build	241	60	181	0	0
4 - 10kW retrofit	23,857	5,964	17,893	0	0
10 - 50kW new build	1,011	0	809	101	101
10 - 50kW retrofit	100,126	0	80,100	10,013	10,013
50-150kW new build	240	0	191	24	24
50-150kW retrofit	23,739	0	18,991	2,374	2,374
150-250kW new build	279	0	253	13	13
150-250kW retrofit	27,595	0	2,760	12,418	12,418
250-5000kW new build	176	0	2	87	87
250-5000kW retrofit	17,408	0	1,741	7,834	7,834
Stand alone	129,081	0	12,908	58,086	58,086
Aggregator <4kW	1,119	1,007	112	0	0
Aggregator >4kW	10,658	6,395	4,263	0	0

2.3 Wind

2.3.1 Data Collection

2.3.1.1 Questionnaire responses were received from a wide range of consultees in relation to wind projects, with 62 project-specific responses received in total, alongside a selection of additional information sources. The final assumptions presented are heavily based on questionnaire responses and the additional information received during the data collection exercise, with in-company expertise drawn upon where necessary to fill in any data gaps. The distribution of data received is as follows:

Capacity bands	<1.5kW	1.5-15kW	15-50kW	50-100kW	100-500kW	500-1500kW	1500-5000kW
Responses/project examples	0	2 (+2 examples)	0	11	39	10	1

2.3.1.2 For wind installations registered under the FITs scheme, information on the capital and operating/maintenance costs has been updated to reflect recent price data. Other adjustments have been made, including changes to load factors, export fractions and average installation size.

2.3.1.3 Details of how inputs to the model have been derived are provided below.

2.3.2 De-rated Turbines

2.3.2.1 “De-rating” is the practise of limiting the electrical output of a wind turbine through reducing the generator size, whereby the manufacturer can state the generator capacity is smaller than the maximum power it is capable of producing. The physical size and external appearance of the de-rated turbine is the same as that of the turbine prior to de-rating. As a result, when the turbine blades are designed for higher capacity turbines, load factors of de-rated turbines are typically higher and the operator benefits from the higher FIT of the lower band. De-rated turbines can also artificially inflate the average Capex cost of turbines within the 100-500kW band since, for example, a larger 900kW turbine de-rated to 500kW will be likely to have a higher capital cost than a 500kW turbine which has not been de-rated.

2.3.2.2 Within this study, Parsons Brinckerhoff has only seen evidence of 800 or 900kW machines de-rated to 500kW and installed under the lower, more economically rewarding tariff band (100-500kW). Instances like this have been identified where the questionnaire response has stated the turbine model installed (for example, an Enercon E44 which has a rated capacity of 900kW) and given a lower installed capacity (generally of 500kW). Out of the 39 data points in the 100-500kW band, 20 (51.3%) were derated turbines.

2.3.3 Average Installation Size

2.3.3.1 The size of a typical installation within each band has been based on the average size of installations within each capacity band registered for FITs to date using data provided by Ofgem. Please note that the Ofgem dataset does not distinguish between urban and rural wind turbines in the smaller capacity bands. The assumptions generated are as follows:

Capacity Band	Average installation size (kW)
B-M <1.5kW urban	1.65
B-M <1.5kW rural	1.65
1.5–15kW urban	7.8
1.5–15kW rural	7.8
15–50kW urban	23.46
15–50kW rural	23.46
50–100kW	79.56
100–500kW	379.01
500–1,500kW	930.69
1,500-5,000kW	2911.02

2.3.4 Export Fraction

2.3.4.1 A central case was estimated for export fractions across each capacity band using the average value of the data received. We have reduced the export fraction for 1.5-15kW after reviewing the data received which largely suggests that facilities with installations of this type use all electricity generated on site. The assumptions generated are as follows:

Capacity Band	Export Fraction (%)
B-M <1.5kW urban/rural	0
1.5–15kW urban	0
1.5–15kW rural	0
15–50kW urban	50
15–50kW rural	75
50–100kW	80
100–500kW	85
500–1,500kW	95
1,500-5,000kW	100

2.3.5 Capex

2.3.5.1 All Capex prices received were adjusted for inflation based on the RPI prior to the methodology outlined below.

2.3.5.2 Capex prices were split as per the existing capacity bands and weightings were applied to each number to adjust them based on Parsons Brinckerhoff's confidence. The median value was found for each group. 75% either side of the median value was calculated in order to remove outliers but these were not found. The median formed the 'central case'. 52% and 148% either side of the central case value forms the respective low and high cases based on one standard deviation of the dataset.

2.3.5.3 No data was received for building mounted turbines.

2.3.5.4 Given the shortage of questionnaire responses and subsequent lack of confidence in the <1.5kW, 1.5-15kW, 15-50kW and 1500-5000kW bands, Parsons Brinckerhoff used the above method to calculate the median values for the 100-500kW and 500-

1500kW bands, then used the cost change between the 2012 and the 2014 assumption to guide the changes for the other bands.

2.3.5.5 The cost difference between 2012 and 2014 data for the 500-1500kW band was used to adjust the 2012 data for 1500-5000kW to a 2014 value. The cost difference between 2012 and 2014 data for the 100-500kW band (excluding derated turbines so as not to artificially inflate the other bands) was used to adjust the 2012 data for <1.5kW, 1.5-15kW and 15-50kW to a 2014 value.

2.3.5.6 While Figure 2:2 generally shows a downward trend in Capex per kW installed with increasing capacity, the data collected for 50-100kW systems lies outside of this assumption, with a much lower Capex in £/kW than the larger turbines. While the questionnaire did not specifically seek to understand exactly how the Capex cost was split between EPC, equipment and installation costs, some qualitative analysis can be done around why this band sits apart from the other data sets.

2.3.5.7 Turbines within the 50-100kW band are generally small, monopole mounted installations, with inbuilt ladders or tilt-up systems installed as standard, limiting the need for large load-bearing concrete foundations found with larger turbine models. While smaller turbines consist of components that are reasonably simple to manufacture and are somewhat more readily available, larger turbines including those in the 100-500kW band utilise more specialised components available from a limited number of specialist manufacturers. For example, the manufacture of larger blades, tubular towers and larger generators require dedicated facilities. Smaller components (including lattice towers and smaller electrical generators) have a much wider market availability as they are often used for applications not related to wind energy generation.

2.3.5.8 Questionnaire data received for the 50-100kW band, once weighted, produced an anomalous result and as such, the average of the un-weighted figures was used to guide the 2014 cost assumption, which brings this assumption in line with the evidence presented above.

2.3.5.9 The final assumptions generated are as follows:

Capacity Band	Capex (£/kW)		
	Low Case	Central Case	High Case
B-M <1.5kW urban/rural	-	-	-
1.5–15kW urban	2,083	3,991	5,899
1.5–15kW rural	2,083	3,991	5,899
15–50kW urban	1,667	3,193	4,719
15–50kW rural	1,667	3,193	4,719
50–100kW	541	1,036	1,531
100–500kW	1,191	2,281	3,371
500–1,500kW	633	1,213	1,792
1,500-5,000kW	576	1,103	1,630

2.3.5.10 Figure 2:2 below shows the distribution of the data received across each capacity band. As no data was received relating to the <1.5kW and 15-50kW bands and only one data point relating to the 1500-5000kW band, these have been removed from the figure. The figure also shows the box and whisker plots for the capacity band 100-

500kW with the de-rated turbines both included and excluded. Further discussion of the de-rated turbine Capex is given in Figure 2:3 and paragraphs 2.3.5.12 - 2.3.5.16 below

2.3.5.11 It should also be noted that the large tariff difference between 100-500kW and 500-1500kW has pushed deployment in the 100-500kW band to the very edge of the band and 92.5% of the data captured within this band was for 500kW turbines (including de-rated models). This therefore represents a skew towards higher Capex within this band.

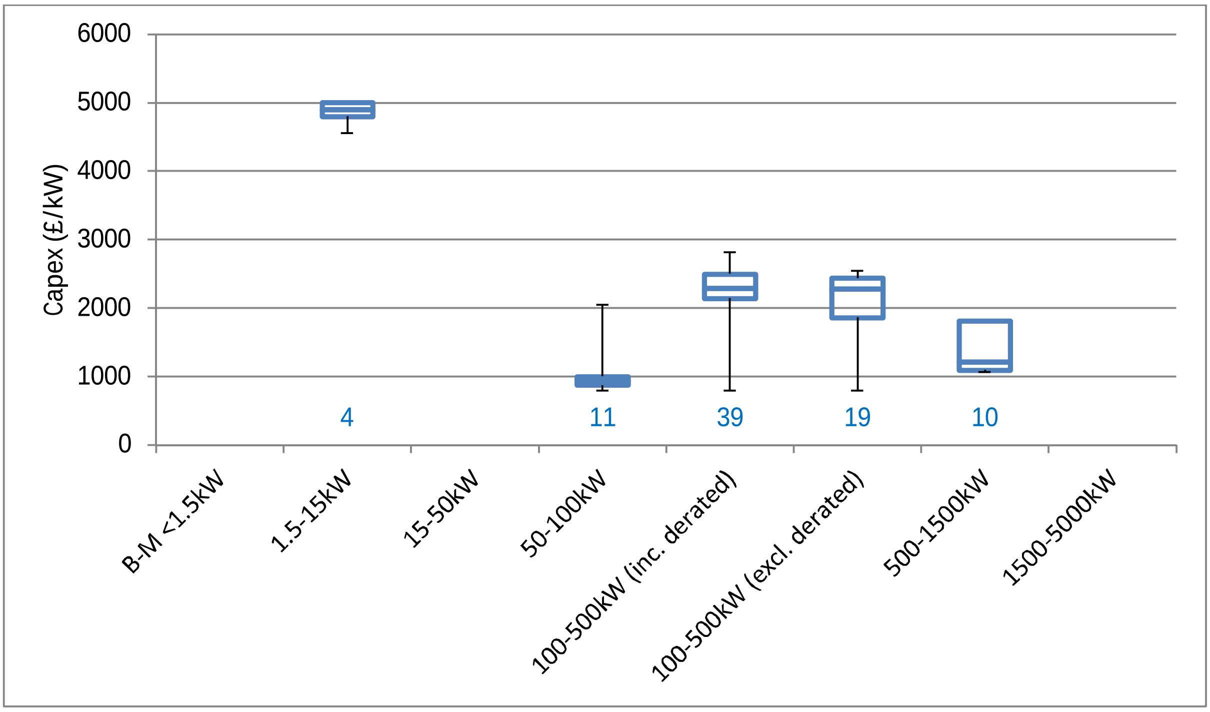

Figure 2:2 Capex data per capacity band (Wind) from questionnaire responses

Please note: *the data presented in Figure 2:2 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.*

2.3.5.12 Further analysis of the Capex of in the 100-500kW band has been carried out in relation to de-rated turbines. This is illustrated in Figure 2:3 below. Columns A and B are the same as those shown in Figure 2:2.

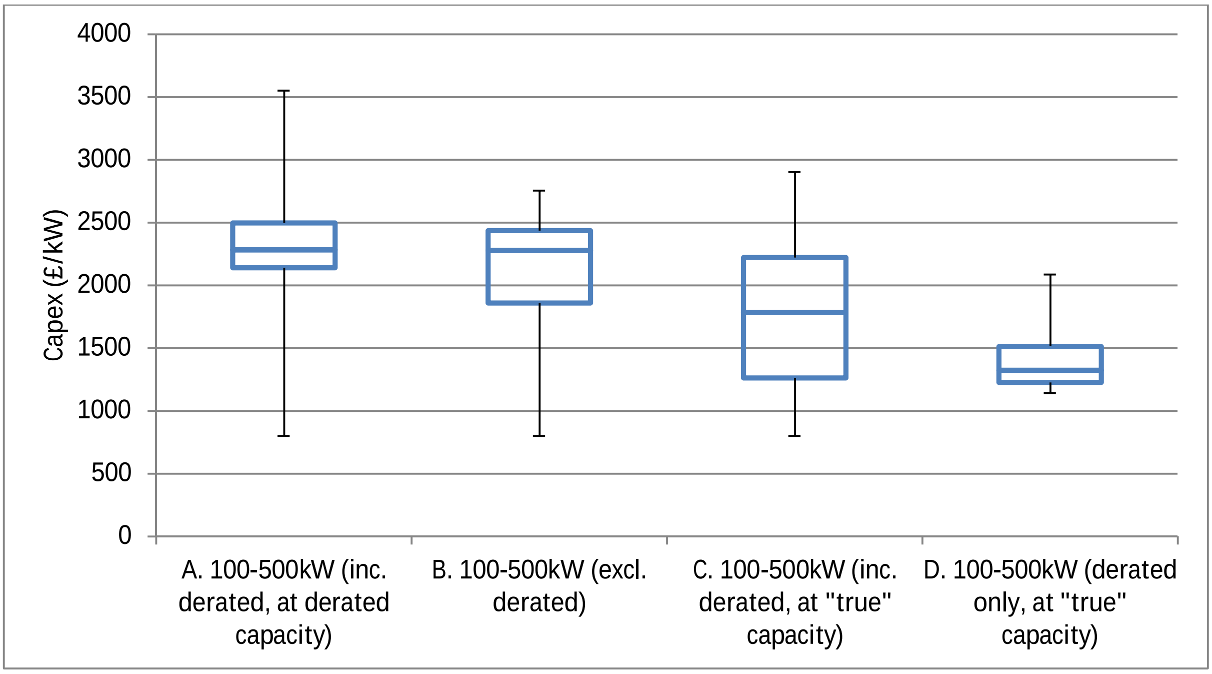

Figure 2:3 Capex data for 100-500kW (Wind) from questionnaire responses

Please note: *the data presented in Figure 2:3 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.*

2.3.5.13 Column A in Figure 2.3 shows the cost range for 100-500kW turbines, including de-rated turbines with Capex/kW calculated using their de-rated capacity.

2.3.5.14 Column B shows the impact on the cost range when de-rated turbines are removed. As expected, the cost range reduces as the artificial inflation noted in section 2.3.2.1 is removed.

2.3.5.15 Column C shows the cost range when de-rated turbine Capex is based on the “true” capacity, i.e. 900kW for a 900kW turbine that has been de-rated to 500kW. The cost/kW for the de-rated turbines is now significantly lower and this results in the reduction in costs when comparing column C to column A.

2.3.5.16 Column D shows the cost range for only the de-rated turbines, again based on their “true” capacity. Costs are lower than for Column C, illustrating the lower cost/kW for the larger de-rated turbines compared to turbines with a “true” capacity in the 100-500kW band.

2.3.6 Forecasting Capex

2.3.6.1 In order to forecast Capex costs, Parsons Brinckerhoff referred to the RenewableUK Onshore Wind Cost Reduction Taskforce report[10] published in April 2015 which states an annual cost reduction rate of just over 4% pa to 2018/2019 and suggests this is a reasonable proxy for the expected 2020 figures.

10 http://www.renewableuk.com/en/publications/index.cfm/Onshore%20Wind%20Cost%20Reduction%20Taskforce%20Report

2.3.7 Opex

2.3.7.1 Opex prices were split as per the existing capacity bands and weightings were applied to each number to adjust them based on Parsons Brinckerhoff's confidence.

2.3.7.2 The median value was then found for each group. Values more than 75% either side of the median value were removed from the analysis. The median (after outliers were removed) formed the 'central case'. 38.6% either side of the central case value forms the low and high cases based on the standard deviation of the data set.

2.3.7.3 As for Capex, no data relating to building-mounted turbines was received during the study.

2.3.7.4 Given the shortage of questionnaire responses and subsequent lack of confidence in the <1.5kW, 1.5-15kW, 15-50kW, 50-100kW, 500-1500kW and 1500-5000kW bands, Parsons Brinckerhoff used the above method to calculate the median values for the 100-500kW, then used the cost change between the 2012 and the 2014 assumption to guide the changes for the other bands. The Opex value for 100-500kW was calculated by excluding derated turbines in this instance, so as not to artificially inflate the Opex costs for the other bands.

2.3.7.5 The final assumptions generated are as follows:

Capacity Band	Opex (£/kW/year)		
	Low Case	Central Case	High Case
B-M <1.5kW urban	-	-	-
B-M <1.5kW rural	-	-	-
1.5–15kW urban	41	66	92
1.5–15kW rural	41	66	92
15–50kW urban	28	45	63
15–50kW rural	28	45	63
50–100kW	25	41	56
100–500kW	35	57	79
500–1,500kW	17	27	38
1,500-5,000kW	17	27	38

2.3.7.6 Figure 2:4 below shows the distribution of Opex data across each capacity band from the survey data gathered. However, the final assumptions generated conclude that Opex costs per kW installed per year generally decrease with capacity. While the questionnaire did not seek to understand why this is the case, it may be that smaller turbines with a faster rotor RPM require more replacement parts over time, and that components are replaced instead of repaired. It may also be the case that manpower requirements are similar for larger and smaller installations, and therefore the cost per kW is higher for smaller units. Other factors may also contribute to this trend and the relative importance of each factor cannot be determined based on the data available from this study.

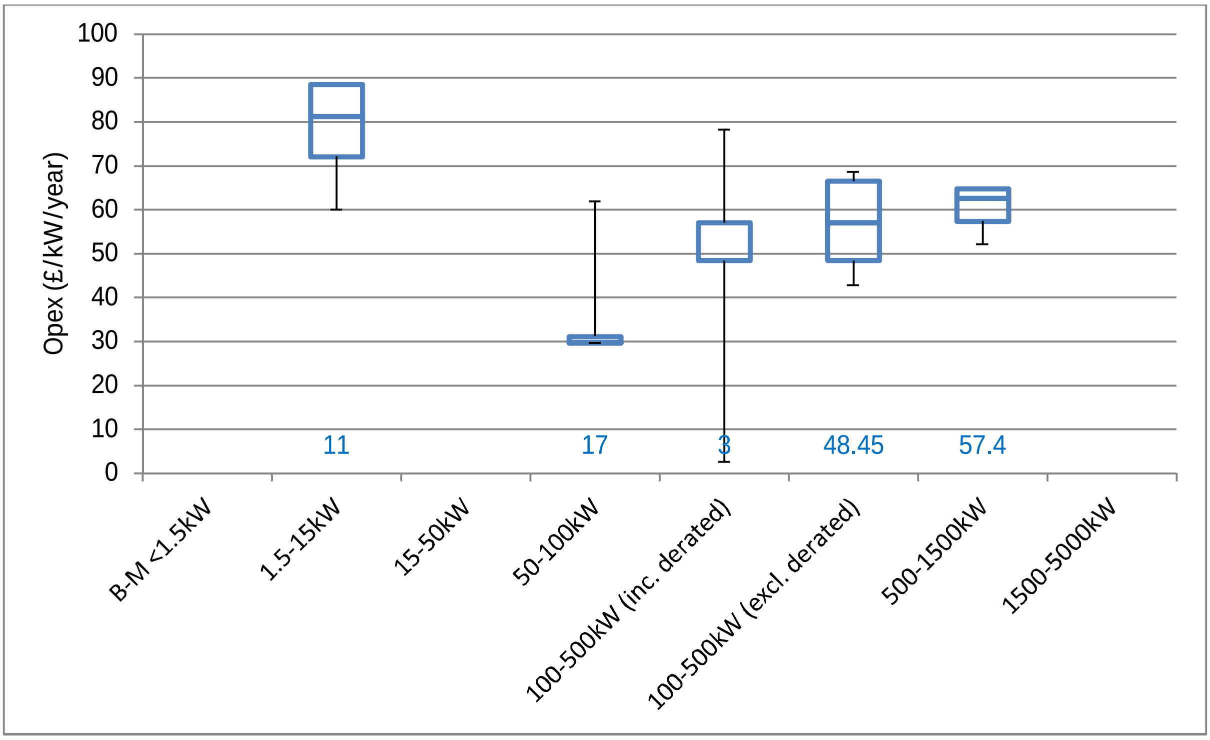

Figure 2:4 Opex data per capacity band (Wind) from questionnaire responses

Please note: *the data presented in Figure 2:4 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.*

2.3.8 Forecasting Opex

2.3.8.1 Opex costs have been decreased year on year in line with a report produced by KIC InnoEnergy – Future renewable energy costs: onshore wind[11] in 2014, which states a 6% reduction in Opex costs between 2014 and 2025. This has been forecast as a linear degression.

2.3.9 Load factors

2.3.9.1 Final load factor assumptions are as follows:

Capacity Band	Low					
	Wind 5.5 m/s	Wind 6 m/s	Wind 6.5 m/s	Wind 7 m/s	Wind 7.5 m/s	Wind 8 m/s
B-M <1.5kW urban	0%	0%	0%	0%	0%	0%
B-M <1.5kW rural	0%	0%	0%	0%	0%	0%
1.5–15kW urban	10%	12%	14%	16%	18%	20%
1.5–15kW rural	14%	17%	20%	23%	26%	29%
15–50kW urban	9%	11%	13%	15%	17%	19%
15–50kW rural	12%	15%	18%	22%	25%	28%
50–100kW	14%	18%	21%	24%	27%	29%

[11] http://www.kic-innoenergy.com/wp-content/uploads/2014/09/KIC_IE_OnshoreWind_anticipated_innovations_impact.pdf

100–500kW	29%	29%	35%	33%	26%	19%
100–500kW (excl. derated turbines)	14%	17%	20%	24%	27%	31%
500–1,500kW	13%	17%	20%	24%	27%	31%
1,500-5,000kW	15%	18%	22%	26%	29%	33%

Capacity Band	Medium					
	Wind 5.5 m/s	Wind 6 m/s	Wind 6.5 m/s	Wind 7 m/s	Wind 7.5 m/s	Wind 8 m/s
B-M <1.5kW urban	0%	0%	0%	0%	0%	0%
B-M <1.5kW rural	0%	0%	0%	0%	0%	0%
1.5–15kW urban	11%	13%	15%	17%	19%	21%
1.5–15kW rural	14%	17%	21%	24%	27%	29%
15–50kW urban	12%	14%	16%	18%	20%	22%
15–50kW rural	13%	17%	21%	24%	28%	29%
50–100kW	16%	19%	22%	25%	28%	30%
100–500kW	30%	35%	43%	42%	36%	30%
100–500kW (excl. derated turbines)	16%	20%	24%	28%	32%	35%
500–1,500kW	18%	22%	26%	30%	34%	38%
1,500-5,000kW	21%	25%	29%	33%	37%	41%

Capacity Band	High					
	Wind 5.5 m/s	Wind 6 m/s	Wind 6.5 m/s	Wind 7 m/s	Wind 7.5 m/s	Wind 8 m/s
B-M <1.5kW urban	0%	0%	0%	0%	0%	0%
B-M <1.5kW rural	0%	0%	0%	0%	0%	0%
1.5–15kW urban	15%	17%	19%	21%	23%	25%
1.5–15kW rural	22%	24%	26%	28%	29%	29%
15–50kW urban	18%	20%	22%	24%	26%	28%
15–50kW rural	22%	24%	26%	28%	29%	32%
50–100kW	17%	21%	24%	27%	29%	31%
100–500kW	32%	37%	58%	50%	42%	34%
100–500kW (excl. derated turbines)	19%	23%	27%	30%	34%	37%
500–1,500kW	20%	24%	29%	33%	37%	40%
1,500-5,000kW	23%	28%	32%	37%	41%	44%

2.3.9.2 Parsons Brinckerhoff reviewed the original 2012 estimates for each band with high, central and low scenarios and recommends continuing to use them. These results were cross-checked with the results from the questionnaires and also compared to the current estimates with several other Parsons Brinckerhoff wind farms in development or in construction where bankable energy assessment were provided.

2.3.9.3 In the period 2012-2014, the number of manufacturers that significantly improved their model performances (efficiency, overall electricity produced) is limited. Most manufacturers released different or bigger models to cope with the uptake in the off-shore market. Capex and production costs have decreased to improve their competitiveness; however, Parsons Brinckerhoff experience suggests that no significant increase of performance was registered in this period.

2.3.9.4 However, the practise of derating turbines has meant that in the 100-500kW band load factors received throughout the data collection exercise were generally higher than previously specified. As such, load factors in the central and high case bands have been updated to reflect the higher load factors seen, with the median value of the capacity band for each average wind speed (where questionnaire data was received) forming the central case. Where questionnaire data did not provide load factor data for a specific wind speed, the mid-point of the data either side of the missing point was used to generate a central case. For all other bands, Parsons Brinckerhoff does not believe that on-shore wind technology has moved forward enough to justify a change in the existing numbers.

2.3.9.5 The history of wind turbines is that of steadily increasing performance as the technology is improved and blade aerodynamic efficiency is optimised. There is therefore the potential that in the future, new wind turbine installations will make use of improved technology to produce higher load factors. It is also conceivable that in some instances, existing wind turbine installations may retrofit (eg. component replacement) or repower using improved technology to yield higher load factors. Since future technology improvements are by their very nature unpredictable, developments in this area might materially alter these conclusions and should be monitored.

2.3.10 <u>Expected lifetime</u>

2.3.10.1 This has been retained at 20 years in line with the previous report. It is not considered that wind technology has changed so significantly in the last two years that it would affect the operational lifetime of the plant.

2.3.11 <u>Hurdle rates</u>

2.3.11.1 The table below displays the hurdle rates for wind that were suggested by Ricardo-AEA using the methodology described in section 2.1.3.

		Hurdle Rate (%)		
		Low	Medium	High
Domestic, small	Min	1.0%	3.0%	5.0%
	Max	9.0%	11.0%	13.0%
	Avg	4.5%	6.5%	8.5%
Commercial developer, medium	Min	3.0%	5.0%	7.0%
	Max	10.0%	12.0%	14.0%
	Avg	6.3%	8.3%	10.3%
Utility, large	Min	3.0%	5.0%	7.0%
	Max	12.0%	14.0%	16.0%
	Avg	6.3%	8.3%	10.3%

2.3.11.2 The figures provided by Ricardo-AEA were compared to the interim results generated by NERA and are comparable with very similar central case values.

2.3.12 Technical Potential

2.3.12.1 CEPA predicted technical potential for wind within their cost of generation update published in 2012. The values used were taken from the DECC model published prior to the 2012 update, after a check to ensure that they were still considered reasonable.

2.3.12.2 Parsons Brinckerhoff has retained these values within this update. There is shortage of revised information since 2012 and, because wind is considered a mature technology and the available land area in the UK will not have changed significantly since 2012, Parsons Brinckerhoff believes these figures and the distribution of potential across the bands are accurate. We have updated the overall technical potential based on the updated load factor assumptions (central case) given within this report.

Capacity Band	Technical Potential (GWh)				
	Total	Domestic	Commercial	Developer	Utility
B-M <1.5kW urban	0	0	0	0	0
B-M <1.5kW rural	0	0	0	0	0
1.5–15kW urban	0	0	0	0	0
1.5–15kW rural	1,610	644	966	0	0
15–50kW urban	0	0	0	0	0
15–50kW rural	1,352	135	1,216	0	0
50–100kW	580	0	580	0	0
100–500kW	3,694	0	0	2,955	739
500–1,500kW	814	0	0	651	163
1,500-5,000kW	3,917	0	0	1,958	1,958

2.4 Hydro

2.4.1 Data Collection

2.4.1.1 Questionnaire responses were received from a wide range of consultees in relation to hydro projects, with 54 project-specific responses received in total, alongside a selection of additional information sources. The final assumptions presented are heavily based on questionnaire responses and the additional information received during the data collection exercise, with in-company expertise drawn upon where necessary to fill in any data gaps. The distribution of data received is as follows:

Capacity bands	<15kW	15-50kW	50-100kW	100-500kW	500-1000kW	1000-2000kW	2000-5000kW
Responses/project examples	9	9	6	15	6	8	0

2.4.1.2 For hydro installations registered under the FITs scheme, information on the capital and operating/maintenance costs has been updated to reflect recent price data. Other adjustments have been made, including changes to load factors, export fractions and average installation size.

2.4.1.3 Details of how inputs to the model have been derived are provided below.

2.4.2 Average Installation Size

2.4.2.1 The size of a typical installation within each band has been based on the average size of installations within each capacity band registered for FITs to date using data provided by Ofgem. The assumptions are as follows:

Capacity Band	Average installation size (kW)
<15kW	8.4
15–50kW	33.36
50–100kW	85.1
100–500kW	345.48
500–1,000kW	754.19
1,000–2,000kW	1518.4
2,000–5,000kW	2253

2.4.3 Export Fraction

2.4.3.1 A central case was estimated for export fractions across each capacity band using the average value of the data received.

Capacity Band	Export Fraction (%)
<15kW	20
15–50kW	75
50–100kW	75
100–500kW	88
500–1,000kW	99
1,000–2,000kW	99

Capacity Band	Export Fraction (%)
2,000–5,000kW	99

2.4.4 Capex

2.4.4.1 All Capex prices received were adjusted for inflation based on the RPI prior to the methodology outlined below.

2.4.4.2 Capex prices were split as per the existing capacity bands and weightings were applied to each number to adjust them based on Parsons Brinckerhoff's confidence.

2.4.4.3 The median value was then found for each group. Values more than 75% either side of the median value were removed from the analysis. The median formed the 'central case'. 48% either side of the central case value forms the low and high cases based on the standard deviation of the data points gathered.

2.4.4.4 Given the shortage of questionnaire responses and subsequent lack of confidence in the 50-100kW, 500-1000kW, 1000-2000kW and 2000-5000kW bands, Parsons Brinckerhoff used the above method to calculate the median values for the 15-50kW and 100-500kW bands, then used the average cost change between the 2012 and the 2014 assumption to guide the changes for the other bands. The <15kW assumption was generated based on survey results alone.

2.4.4.5 The assumptions generated are as follows:

Capacity Band	Capex (£/kW)		
	Low Case	Central Case	High Case
<15kW	1,873	3,603	5,332
15–50kW	2,900	5,577	8,254
50–100kW	2,682	5,158	7,635
100–500kW	2,158	4,150	6,143
500–1,000kW	1,694	3,258	4,822
1,000–2,000kW	1,331	2,560	3,789
2,000–5,000kW	1,089	2,095	3,100

2.4.4.6 Figure 2:5 below shows how the distribution of the data varies with each capacity size. It is evident from the data presented in Figure 2:5 that there is not a clear trend in Capex for hydro schemes across the capacity bands; Parsons Brinckerhoff's view is that the likely reason for an absence of a trend is because each hydro project is unique in its construction and design requirements. The distribution of data within each capacity band is very large, even when outliers have been removed from the data sets. Note that due to a shortage of data collected, the box and whisker plot for Capex of 2000-5000kW projects has not been included.

2.4.4.7 The data suggests that determining an average Capex value for hydro projects across any of the capacity bands is difficult given the varying levels of design and build complexity. While Parsons Brinckerhoff has more confidence in the <15kW, 15-50kW, and 100-500kW than the other bands given the larger quantities of questionnaire data received, the data are still largely spread, both across the individual bands and across the entire data set.

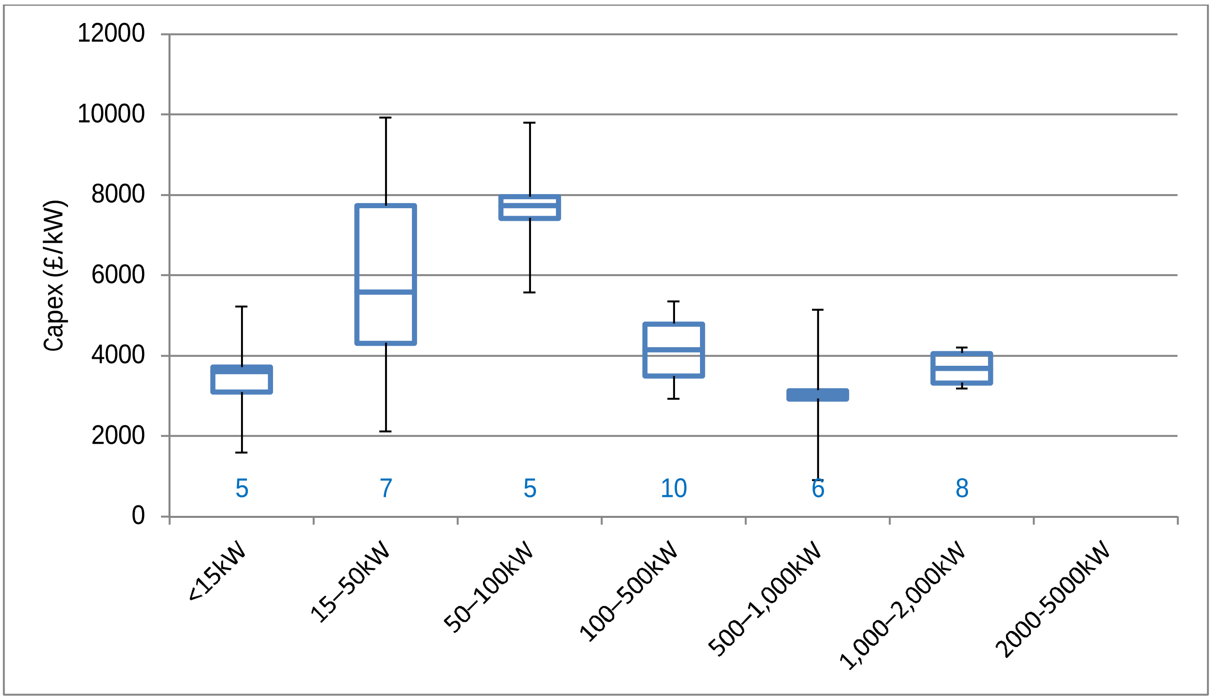

Figure 2:5 Capex data per capacity band (Hydro) from questionnaire responses

Please note: *the data presented in Figure 2:5 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.*

2.4.5 Forecasting Capex

2.4.5.1 Parsons Brinckerhoff referred to the IRENA Renewable Power Generation Costs in 2014 report which confirms that hydro is a mature technology with limited cost reduction potential. Parsons Brinckerhoff has therefore assumed a 0% per year linear cost reduction up to 2021; this figure is used as a balance between small changes in manufacturing methods which may decrease hydro Capex costs and rising installation costs across more complex sites.

2.4.6 Opex

2.4.6.1 Opex prices were split as per the existing capacity bands and weightings were applied to each number to adjust them based on Parsons Brinckerhoff's confidence.

2.4.6.2 The median value was then found for each group. Values more than 75% either side of the median value were removed from the analysis. The median formed the 'central case'. 94.2% either side of the central case value forms the low and high cases.

2.4.6.3 Given the shortage of questionnaire responses relating to Opex costs, Parsons Brinckerhoff only had real confidence in the 100-500kW and 1000-2000kW bands, Parsons Brinckerhoff used the above method to calculate the median values for these bands, then used the cost change between the 2012 and the 2014 assumption to guide the changes for the other bands.

2.4.6.4 The cost difference between 2012 and 2014 data for the 100-500kW band was used to adjust the 2012 data for <15kW, 15-50kW and 50-100kW bands to their 2014 value. The cost difference between 2012 and 2014 data for the 1000-2000kW band was used to adjust the 2012 data for 2000-5000kW to a 2014 value. The average of the two costs differences was used to calculate the cost change for the 500-1000kW band.

2.4.6.5 The final assumptions generated are as follows:

Capacity Band	Opex (£/kW/year)		
	Low Case	Central Case	High Case
<15kW	2	42	82
15–50kW	4	67	130
50–100kW	5	93	181
100–500kW	3	51	99
500–1,000kW	1	21	41
1,000–2,000kW	1	12	23
2,000–5,000kW	0	5	10

2.4.6.6 Figure 2:6 shows how the distribution of the data varies with each capacity size. The trend largely shows decreasing annual operational costs per kW with increasing project capacity.

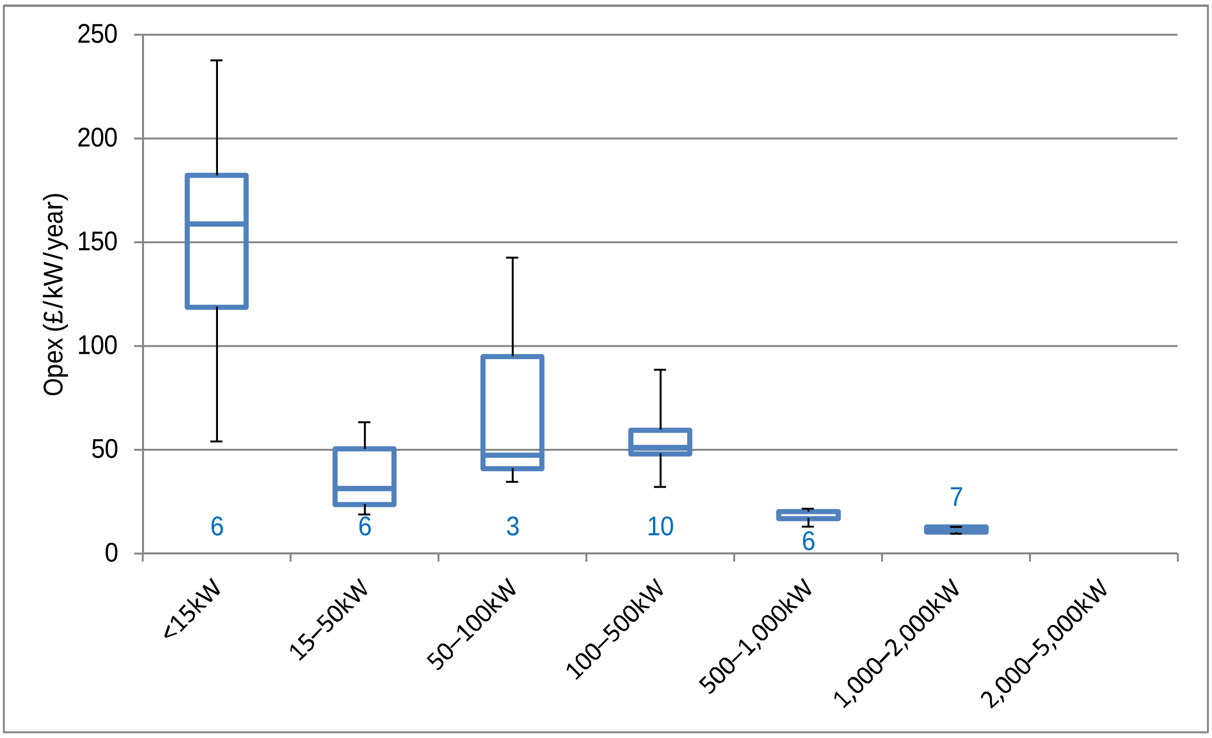

Figure 2:6 Opex data per capacity band (Hydro) from questionnaire responses

Please note: *the data presented in Figure 2:6 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.*

2.4.7 Forecasting Opex

2.4.7.1 Opex costs have not been changed while predicting forward as it is not envisaged that methods around operating and maintaining hydro generating plant will change. This is in line with the figures predicted during the 2012 report.

2.4.8 Load factors

2.4.8.1 The load factors presented below have been increased in comparison to 2012 assumptions.

2.4.8.2 The central case load factor assumption was generated by calculating the median of the questionnaire data collected. One standard deviation of this data either side provides the low and high cases.

Load Factor (%)		
Low	**Central**	**High**
27%	40%	53%

2.4.8.3 Much higher load factors were witnessed in the questionnaire responses, particularly in relation to turbines <15kW, where operational load factors as high as 70% were seen, and anticipated load factors of 85% were stated.

2.4.8.4 Parsons Brinckerhoff also recognise that turbines are sometimes undersized for the water course they are installed in, possibly as a result of grid availability in more rural areas, which leads to distorted, higher load factors. While these load factors were included in the calculation of the cases presented above, the high case was not skewed to include these higher load factor instances.

2.4.9 Expected lifetime

2.4.9.1 Responses to the survey state that the useful project life (economic life) for hydro installations is 25–75 years with an average value of 35 years. While the civil structure and the turbine can exist for huge lengths of time, the electrical and Balance of Plant components may need replacing after 15-20 years and as such, 35 years has been assumed as a reasonable lifetime. This has been increased in comparison to the 2012 report, which stated a 25 year lifetime.

2.4.10 Hurdle rates

2.4.10.1 The table below displays the hurdle rates for hydro that were suggested by Ricardo-AEA using the methodology as described in section 2.1.3.

		Hurdle Rate (%)		
		Low	Medium	High
Domestic, small	Min	1.00%	3.00%	5.00%
	Max	9.00%	11.00%	13.00%
	Avg	4.50%	6.50%	8.50%
Commercial developer, medium	Min	7.00%	9.00%	11.00%
	Max	13.00%	15.00%	17.00%
	Avg	9.00%	11.00%	13.00%

Utility, large	Min	5.00%	7.00%	9.00%
	Max	13.00%	15.00%	17.00%
	Avg	6.50%	8.50%	10.50%

2.4.10.2 The assumptions provided by Ricardo-AEA were compared to the interim results generated by NERA and were found to be very similar, although the ranges are different particularly at the high end.

2.4.11 Technical Potential

2.4.11.1 CEPA predicted technical potential for hydro within their cost of generation update published in 2012. These values were derived from the 2010 Environment Agency report 'Mapping Hydropower Opportunities and Sensitivities in England and Wales'[12] and the 2009 Element Energy/Poyry report on the Feed-In Tariff Design.

2.4.11.2 As hydro is considered a mature technology and the number of rivers/water bodies in the UK has not changed since 2012, Parsons Brinckerhoff believes the power potential figures given in the Environment Agency report are still accurate. This report was used to guide the 2014 technical potential assumptions.

2.4.11.3 The power potential figures given within the Environment Agency report were split into the current FIT capacity bands shown below and multiplied by the central case load factor given in 2.4.8 above to determine a technical potential figure for each capacity band. The distribution of this potential generation across domestic, commercial, developer and utility-scale projects within each band was retained as for the 2012 assumptions.

Capacity Band	Technical Potential (GWh)				
	Total	Domestic	Commercial	Developer	Utility
<15kW	305	229	76	0	0
15–50kW	553	24	144	385	0
50–100kW	441	0	44	353	44
100–500kW	1,365	0	0	683	682
500–1,000kW	618	0	0	309	309
1,000–2,000kW	769	0	0	384	384
2,000–5,000kW	902	0	0	451	451

[12] Mapping Hydropower Opportunities and Sensitivities in England and Wales – Technical Report, Environment Agency, February 2010. Available at: http://www.climate-em.org.uk/images/uploads/GEHO0310BRZH-E-E_technical_report.pdf

2.5 Anaerobic Digestion

2.5.1 Data Collection

2.5.1.1 A total of 21 project-specific questionnaire responses were received for AD projects, alongside a selection of additional information sources and specialist input provided by WSP. The final assumptions presented are heavily based on questionnaire responses and the additional information received during the data collection exercise, with in-company expertise drawn upon where necessary to fill in any data gaps. The distribution of data received is as follows:

Capacity bands	<250kW	250-500kW	>500kW
Responses/project examples	4 (+17 Capex/Opex data only)	12 (5 with no cost data)	5

2.5.1.2 For AD installations registered under the FITs scheme, information on the capital and operating/maintenance costs has been updated to reflect recent price data. Other adjustments have been made, including changes to load factors, export fractions and average installation size.

2.5.1.3 Details of how inputs to the model have been derived are provided below.

2.5.2 Average Installation Size

2.5.2.1 The size of a typical installation within each band has been based on the average size of installations within each capacity band registered for FITs to date using data provided by Ofgem. The assumptions are as follows:

Capacity Band	Average installation size (kW)
AD < 250kW	155.26
AD 250 - 500kW	479
AD > 500kW	1414.81

2.5.3 Export Fraction

2.5.3.1 A central case was estimated for export fractions across each capacity band using the average value of the data received.

Capacity Band	Export Fraction (%)
AD < 250kW	75
AD 250 - 500kW	90
AD > 500kW	95

2.5.4 Capex

2.5.4.1 All Capex prices received were adjusted for inflation based on the RPI prior to the methodology outlined below.

2.5.4.2 Capex prices were split as per the existing capacity bands and weightings were applied to each number to adjust them based on Parsons Brinckerhoff's confidence.

2.5.4.3 The median value was then found for each group. Values more than 75% either side of the median value were removed from the analysis.

2.5.4.4 Given the shortage of questionnaire responses and subsequent lack of confidence in the 250-500kW and >500kW bands, Parsons Brinckerhoff used the above method to calculate the median for the <250kW band, then used the cost change between the 2012 and the 2014 assumption to guide the change for the >500kW band.

2.5.4.5 Using this method suggested that the Capex costs for the 250-500kW band were closer to >500kW. Questionnaire responses showed that this is not accurate and that the Capex value for 250-500kW projects is closer to the <250kW value. Additional operational project examples provided by WSP and shown in Figure 2:7 below also demonstrated that projects within the <250kW and 250-500kW bands are much similar in nature in terms of Capex than those in the >500kW.

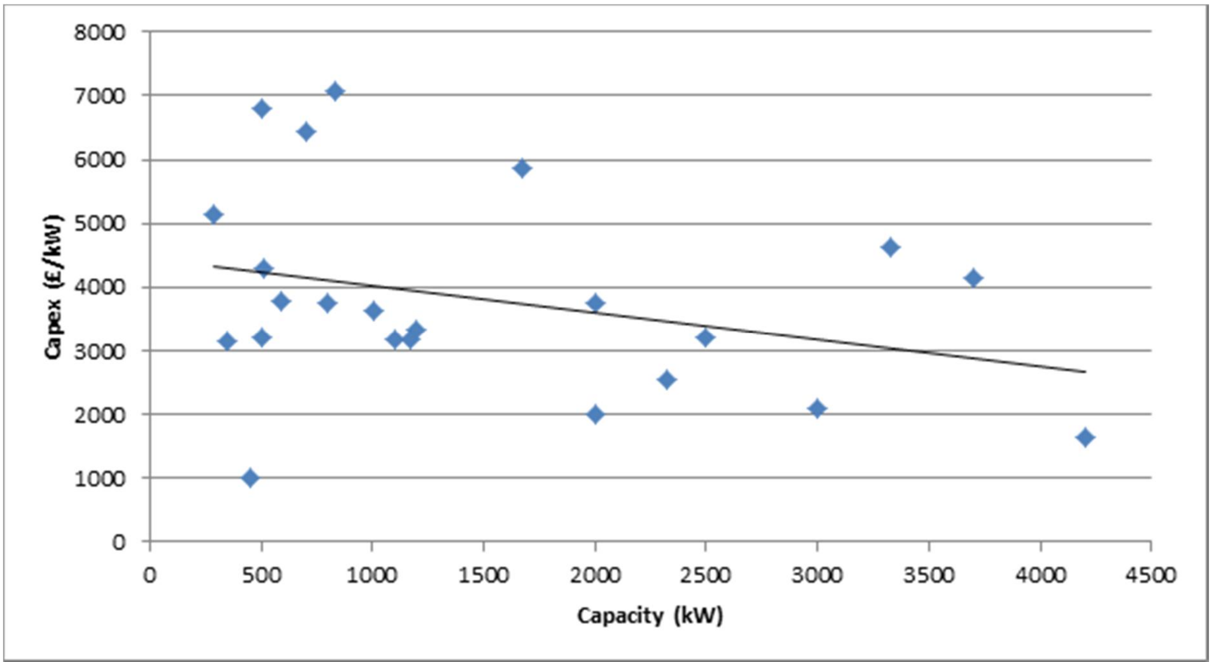

Figure 2:7 Capex of additional operational AD project examples (provided by WSP)

2.5.4.6 Therefore, Parsons Brinckerhoff used the mean value of the 250-500kW data set to generate a sensible scale assumption, with 36.5% either side of the central case value forming the low and high cases, based on the standard deviation of the data received.

2.5.4.7 The assumptions generated are as follows:

Capacity Band	Capex (£/kW)		
	Low Case	Central Case	High Case
< 250kW	3,780	5,953	8,126
250 - 500kW	3,685	5,804	7,922
> 500kW	2,835	4,465	6,095

2.5.4.8 Figure 2:8 below shows the capital expenditure per kW installed for each capacity band. In general, the trend shows decreasing capital costs with increasing project size, although the variation around the smaller plants is large, possibly due to the different types of feedstock processed and therefore different plant configurations.

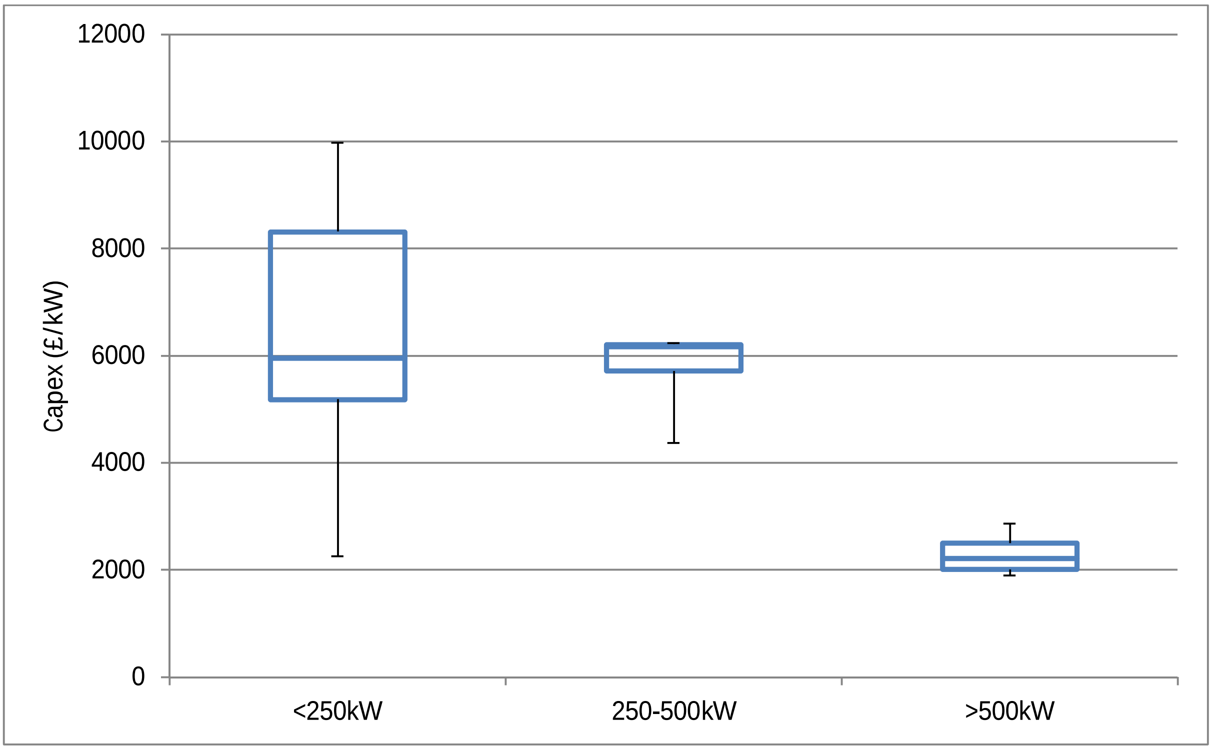

Figure 2:8 Capex data per capacity band (AD) from questionnaire responses

__Please note:__ the data presented in Figure 2:8 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.

2.5.5 Forecasting Capex

2.5.5.1 No formal reports were identified that provided evidenced figures for a forecasted change in Capex costs relating to AD. Parsons Brinckerhoff has employed the use of their in-house Technical Leadership Team to determine suitable assumptions for the future costs of AD.

2.5.5.2 Capex costs have been forecast in line with predictions assumed under the previous work completed by CEPA. This is based on the assumption that the technology will continue to mature slightly, allowing for some further small reductions in cost, largely through reduction in project risks. Capex costs have been forecasted at decreasing 1% annually until 2021, from which point onwards they will decrease by 0.5% per year.

2.5.6 Opex

2.5.6.1 Opex prices were split as per the existing capacity bands and weightings were applied to each number to adjust them based on Parsons Brinckerhoff's confidence.

2.5.6.2 The median value was then found for each group. Values more than 75% either side of the median value were removed from the analysis. The median formed the 'central case'. 64.7% either side of the central case value forms the low and high cases, based on the standard deviation of the data received.

2.5.6.3 Given the shortage of questionnaire responses and subsequent lack of confidence in the 250-500kW and >500kW bands, Parsons Brinckerhoff used the above method to calculate the median for the <250kW band, then used the cost change between the 2012 and the 2014 assumption to guide the changes for the other two bands.

2.5.6.4 The assumptions generated are as follows:

Capacity Band	Opex (£/kW/year)		
	Low Case	Central Case	High Case
< 250kW	268	759	1,250
250 - 500kW	228	645	1,062
> 500kW	240	679	1,118

2.5.6.5 Figure 2:9 below shows the annual operating costs per kW across the different capacity bands. The trend largely shows that with increasing project size, annual operating costs per kW decrease. Uncertainty around the smaller projects (<250kW) is large as methods of operation and maintenance vary significantly, from dedicated Operation & Maintenance contracts to owner-made repairs.

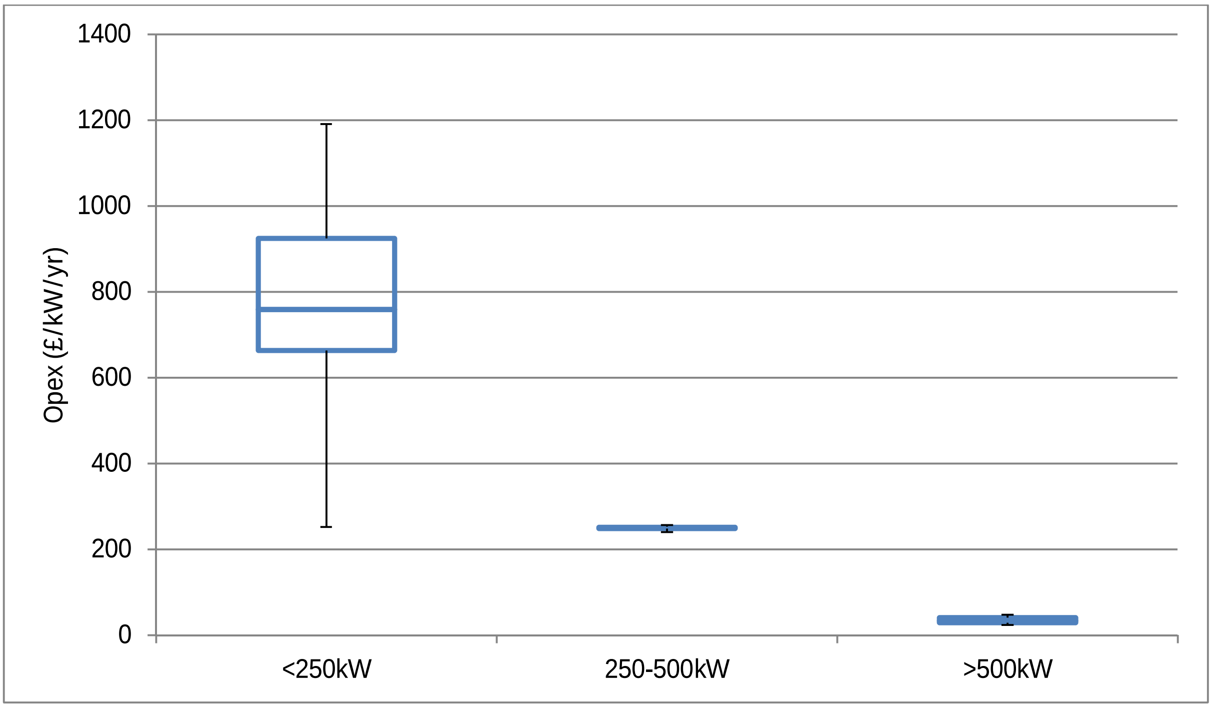

Figure 2:9 Opex data per capacity band (AD) from questionnaire responses

Please note: *the data presented in Figure 2:9 does not necessarily match the data presented in the tables above. Please refer to paragraph 2.1.1.9 for an explanation.*

2.5.6.6 Please refer to paragraph 3.3 for further analysis on feedstock types and costs, and paragraph 3.5 for discussion around digestate disposal costs. The Opex costs quoted above are exclusive of feedstock and digestate disposal costs.

2.5.7 Forecasting Opex

2.5.7.1 No formal reports were identified that provided evidenced figures for a forecasted change in Capex costs relating to AD. Parsons Brinckerhoff has employed the use of their in-house Technical Leadership Team to determine suitable assumptions for the future costs of AD.

2.5.7.2 Future Opex costs are assumed to be flat, as in the previous assumptions. This assumption was confirmed by the Parsons Brinckerhoff Technical Leadership Team. Operations and maintenance varies wildly across the capacity bands, with smaller installations maintained by the farmers who own them, and larger installations with a dedicated Operation & Maintenance contract reflective of the project lifetime.

2.5.8 Load factors

2.5.8.1 The load factor is defined as the actual output over a year compared to the output from the installed capacity running continually throughout the year.

2.5.8.2 Load factors and efficiencies for AD across all capacity bands are higher than in the previous model, based on collected data on actual load factors achieved in practice by UK installations.

Capacity Band	Electricity Load Factor (%)		
	Low	Medium	High
AD < 250kW	63%	65%	67%
AD 250 - 500kW	68%	70%	72%
AD > 500kW	77%	80%	83%

2.5.8.3 Questionnaire data received suggested that load factors were higher than the assumptions given in the table above, at around 90-94% across all capacity bands; however, further review from WSP confirmed that these were likely to be load factors which excluded availability, and that once availability (be it seasonal or as a result of feedstock availability or maintenance) was taken into account, load factors would be much closer to those quoted in the table above.

2.5.8.4 These load factors in line with those quoted by the Green Investment Bank[13] which state an ‘operational performance for agricultural facilities in 2014 [of] 71 per cent… [with a] corresponding figure [of] 72 per cent for source segregated food facilities’.

2.5.9 Expected lifetime

2.5.9.1 This has been retained at 20 years in line with the previous report. It is not considered that AD technology has changed so significantly in the last two years that it would affect the operational lifetime of the plant.

2.5.10 Hurdle rates

[13] The UK Anaerobic Digestion Market, Green Investment Bank, March 2015. Available at http://www.greeninvestmentbank.com/media/44758/gib-anaerobic-digestion-report-march-2015-final.pdf

2.5.10.1 The table below displays the hurdle rates for AD that were suggested by Ricardo-AEA using the methodology as described in section 2.1.3.

		Hurdle Rate (%)		
		Low	Medium	High
Commercial developer, medium	Min	7.0%	9.0%	11.0%
	Max	12.0%	14.0%	16.0%
	Avg	11.0%	13.0%	15.0%
Utility, large	Min	6.0%	8.0%	10.0%
	Max	11.0%	13.0%	15.0%
	Avg	10.0%	12.0%	14.0%

2.5.10.2 The hurdle rates provided by Ricardo-AEA appear to be reasonably comparable to those calculated by NERA. The central case value is slightly higher for Ricardo-AEA however the ranges are similar overall.

2.5.11 <u>Technical Potential</u>

2.5.11.1 CEPA predicted technical potential for AD within their cost of generation update published in 2012. This potential was based on DEFRA's 2011 Anaerobic Digestion Strategy and Action Plan, taking into account the expectation that waste reduction measures will reduce potential over time. Parsons Brinckerhoff has used these values as it is our belief that they still reflect the current technical potential within the UK, but have used the 2014 load factor assumptions (central case) given within this report to update the total technical potential.

2.5.11.2 The technical potential assumptions are as follows:

Capacity Band	Technical Potential (GWh)				
	Total	Domestic	Commercial	Developer	Utility
AD < 250kW	867	0	433	433	0
AD 250 - 500kW	862	0	172	689	0
AD > 500kW	1,600	0	0	1,600	0

2.6 Micro CHP

2.6.1 Average Installation Size

2.6.1.1 The size of a typical installation for mCHP has been based on the average size of installation registered for FITs to date using data provided by Ofgem.

Capacity Band	Average Installation Size (kW)
<2kW	1.04

2.6.2 Export Fraction

2.6.2.1 The value calculated for export fraction was based on heat demand modelling results from the Baxi Ecogen (Stirling engine) system. This range varies from 14-26% and is based on the understanding that the UK average daily electricity demand is lower in the morning and higher in the evening, whereas heat demand is generally highest in the morning through the winter. As such, a reasonable proportion of generated electricity could be exported to the grid, but this would vary according to household power consumption.

Capacity Band	Export Fraction (%)
<2kW	20

2.6.3 Capex

2.6.3.1 Due to a lack of survey responses, Capex data was based on installation prices for the only mCHP systems seemingly available for installation in the United Kingdom – the Baxi Ecogen (Stirling engine).

2.6.3.2 An average value was taken from the two systems available (natural gas and LPG models) to give a Capex price. The low case was calculated from the sale price of the cheaper system (£7,615) with a £1,800 installation cost, and the high case calculated from the full price system cost of the more expensive system (£8,642), with a £1,800 installation cost.

Capacity Band	Capex (£/kW)		
	Low	Central	High
<2kW	9,415	9,929	10,442

2.6.4 Opex

2.6.4.1 Due to a lack of survey responses, Opex data was based on estimates of typical annual boiler servicing costs and through the modelling of heat demand based on the Baxi Ecogen (Stirling engine) system.

Capacity Band	Capex (£/kW)		
	Low Case	Central Case	High Case
<2kW	50	63	75

2.6.5 Load factors

2.6.5.1 The assumption for load factor was calculated based on estimates for annual domestic heat load requirement profiling previously completed in house by Parsons Brinckerhoff and on heat demand modelling completed for the Baxi Ecogen (Stirling engine) system. Load factors are expected to be in the range of 14-38%.

Capacity Band	Load Factor (%)
<2kW	26

2.6.6 Expected lifetime

2.6.6.1 A lifetime of 10 years has been estimated based on publically available information relating to mCHP systems and lifetimes guaranteed by manufacturers.

2.6.7 Hurdle rates

2.6.7.1 Hurdle rates for micro-CHP were not evaluated by Ricardo-AEA or NERA.

3 REVIEW OF OTHER INPUTS

3.1.1.1 The following section outlines further work completed in relation to a number of key questions raised by DECC and other stakeholders throughout the data collection exercise.

3.2 Grid Connection Costs

3.2.1.1 Grid connection costs can form a large part of a project's capital outlay. Parsons Brinckerhoff has collected project specific grid connection details as part of this exercise in a bid to understand how connection costs, types and project distance from the point of grid connection affects project feasibility. Grid connection costs were requested as a separate item within the project pricing details sought by the questionnaires.

3.2.1.2 The following graphs contain data from real wind, hydro and AD project examples to show how the cost of grid connection varies with distance from the point of connection (PoC) and type of connection. Figure 3:1 shows all data points received, while Figure 3:2 shows those less than 2km from the point of connection.

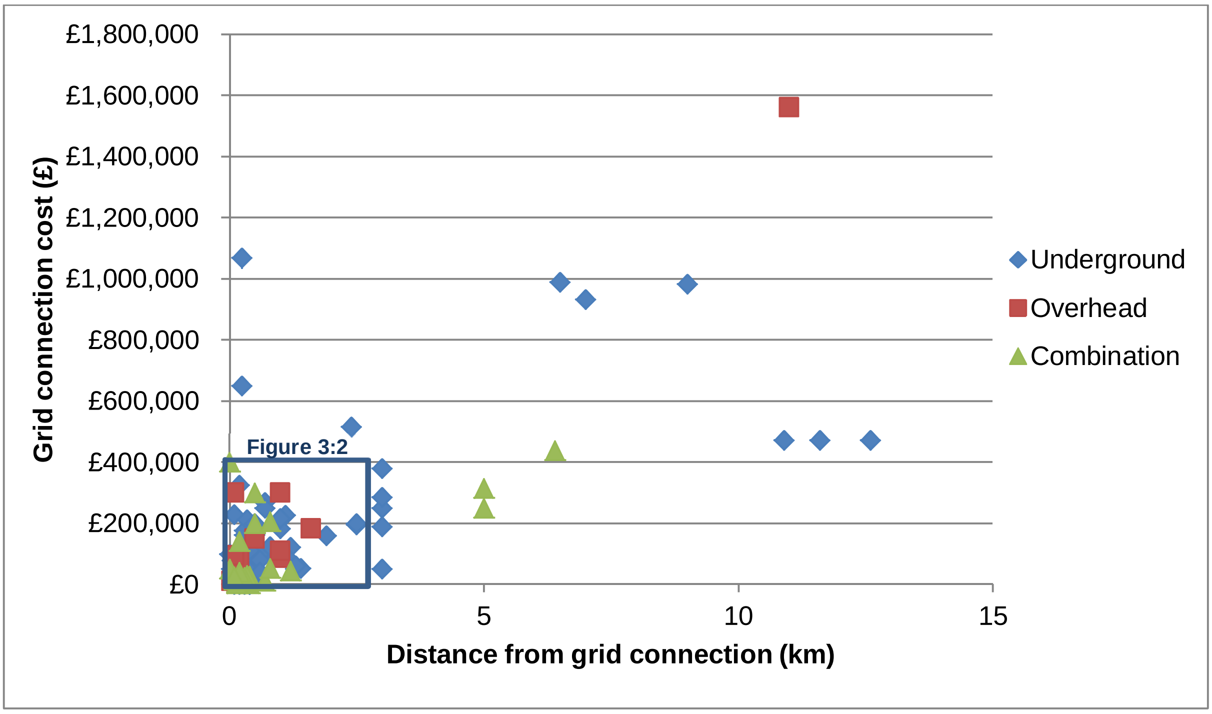

Figure 3:1 The variation of grid connection costs with distance from the PoC

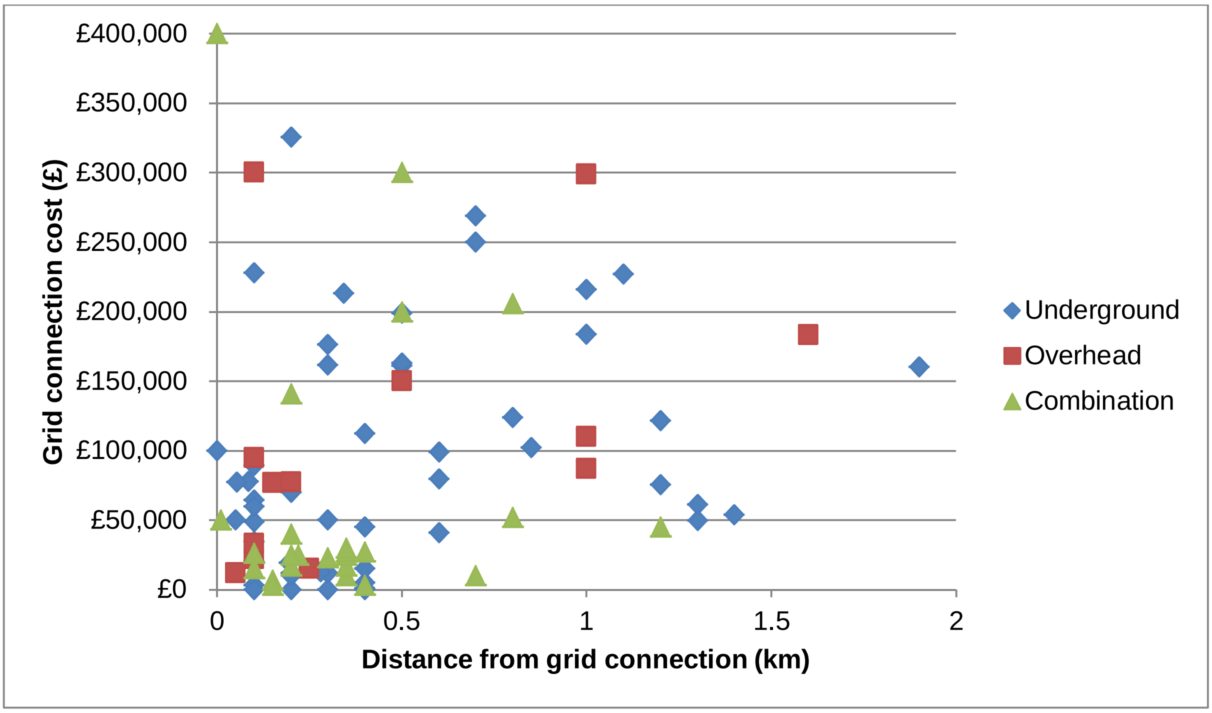

Figure 3:2 The variation of grid connection costs with distance from the PoC

3.2.1.3 The figures above suggest that there is no correlation between grid connection cost and the distance to PoC operated by the local district network operator, regardless of connection type.

3.2.1.4 Naturally, the greater the distance from the generating facility to the PoC, the higher the costs of transmission lines and associated work and this cost alone would display a correlation between cost and distance. However, grid connection costs can be largely dependent on the PoC itself as additional costs are incurred when upgrades have to be made at the substation to accommodate the incoming energy from the connected generating facility. These upgrades will vary hugely depending on the PoC and different capacity connections will force different upgrades. As a result of this, the graph above shows no correlation and connections costs are unable to be predicted.

3.2.1.5 The connection process applies to all technologies eligible under the FIT and due to the huge variability in general connection requirements, it is envisaged that there will be no definitive correlation between cost, technology, capacity and distance.

3.2.1.6 It is worth noting that smaller projects (typically <50kW) can often be connected to localised distribution boards (such as in domestic/commercial properties) in place of being connected to a substation, which therefore incurs no grid connection cost.

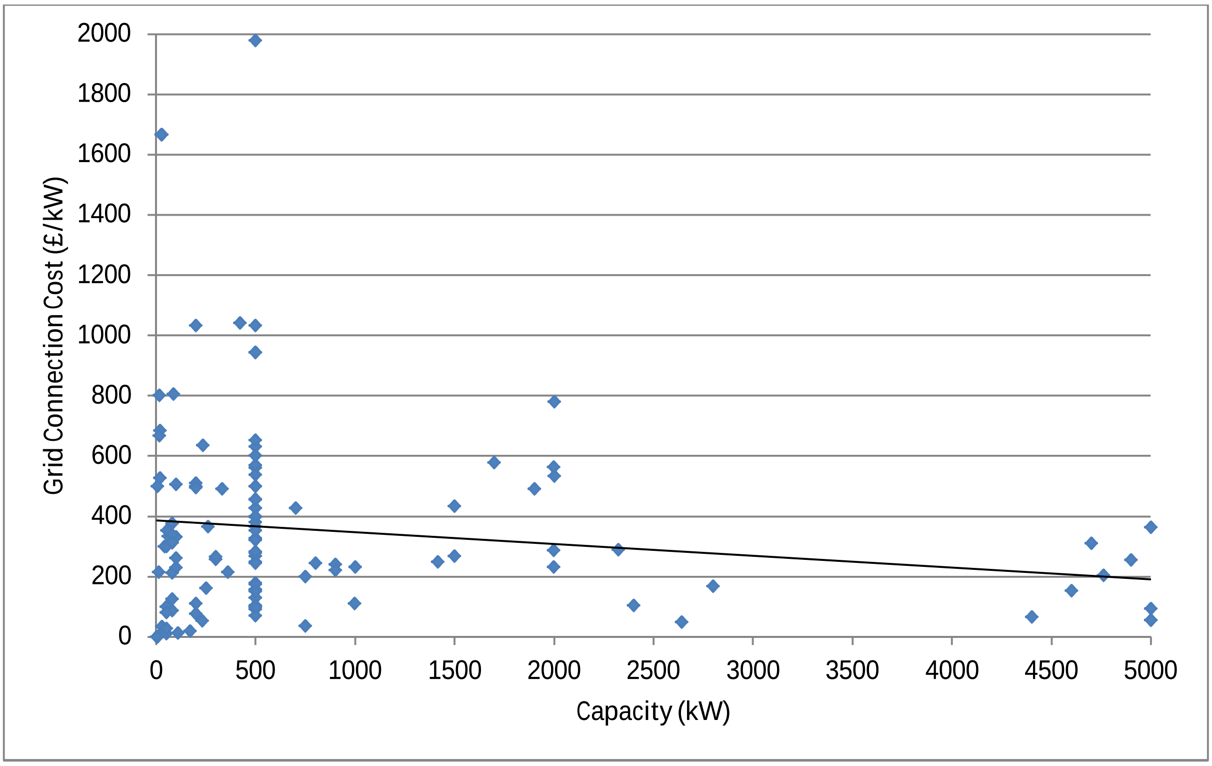

Figure 3:3 Grid connection costs against capacity for all questionnaire responses received

3.2.1.7 Figure 3:3 above shows how grid connection costs (in £/kW) vary with project capacity, using data on grid connection costs obtained from 131 questionnaire responses. There is a weak negative correlation between the two variables, although the number of data points at 500kW demonstrates just how much grid connection costs can vary from project to project.

3.2.1.8 Parsons Brinckerhoff approximated grid connection costs for the capacity bands across this study, by drawing a linear trendline through the data and using the mid-point of the following capacity bands. The following table outlines the suggested central case for grid connection costs across the small-scale renewable technology range:

Capacity Band	Grid Connection Cost (Central case) (£/kW)
0–15kW	£385.60
15–50kW	£384.62
50–100kW	£382.97
100–500kW	£374.19
500–1,500kW	£346.89
1,500-5,000kW	£259.14

3.3 Feedstock Types, Costs and Gate Fees – Anaerobic Digestion

3.3.1.1 The questionnaires issued to industry for anaerobic digestion projects sought to understand the types of feedstock used across each capacity bands and the associated costs and supply chains for these feedstock types. Opex costs quoted within this report are exclusive of feedstock costs and gate fees.

3.3.1.2 Consultees were asked for the types of feedstock used, the volume and associated costs and details relating to their security of supply and feedstock contracts. The tables below shows the data collected from survey responses as to the type and cost of feedstock used in AD plants across the capacity bands.

	Average cost (£/tonne)							
Feedstock	Agricultural (manure)	Agricultural (other)	Crops (maize)	Crops (grass)	Crops (other)	Agricultural (feed waste)	Food Waste	Other
Cost	£0 when 'waste product' £14 when purchased	£15	£28	£25	£24	£0	£30*	£15
Gate Fee	-	-	-	-	-	-	£40**	£6

*Based on one data point received for a 250-500kW plant. Parsons Brinckerhoff do not believe this to be a representative value as food waste is typically a 'gate fee', generating revenue for the operator, not a cost.
**Although no questionnaire data was collected that gave a confirmed gate fee for food waste, the WRAP Gate Fees report 2014 (discussed in section 3.4 below) states that the median value of their data collection exercise was £40. In lieu of any questionnaire data, Parsons Brinckerhoff has used this value as a means to calculate food waste gate fees.

3.3.1.3 The data gathered suggests that all AD plants in the <250kW band use agricultural slurry/manure as their primary feedstock, with volumes varying from 1,300 to 12,000 tonnes per year. It is anticipated that this feedstock is a by-product of their other farming activities and as such, is available free of charge.

3.3.1.4 AD plants in the 250-500kW band vary between using crops (particularly maize or grass) and agricultural slurry/manure or other waste as their primary feedstock. Only one survey respondent (a small industrial system) was paid gate fees for their fuel source which they specified as 'other' and which totalled £160,000pa. Feedstock volumes used per annum varied from 8,000 to 26,500 tonnes per year.

3.3.1.5 Data collected relating to AD plants >500kW suggests that most plants use purpose grown crops for digesting, particularly grass. While one survey respondent confirmed that they use 30,000 tonnes of food waste per year, they did not specify the gate fee they received. Only one project used agricultural slurry/manure and the volume of this made up half of their total annual fuel source. Feedstock volumes used per annum varied from 10,200 to 60,000 tonnes per year.

3.3.1.6 The average feedstock use per capacity band can be depicted as follows and demonstrates that agricultural waste makes up the majority of feedstock for plants smaller than 500kW. Base on the survey data, food waste feed stock is more prevalent in plants larger than 500kW.

3.3.1.7 The table below illustrates the number of data points used for each band.

Capacity Band	<250kW	250-500kW	>500kW
Data Points	12	4	5

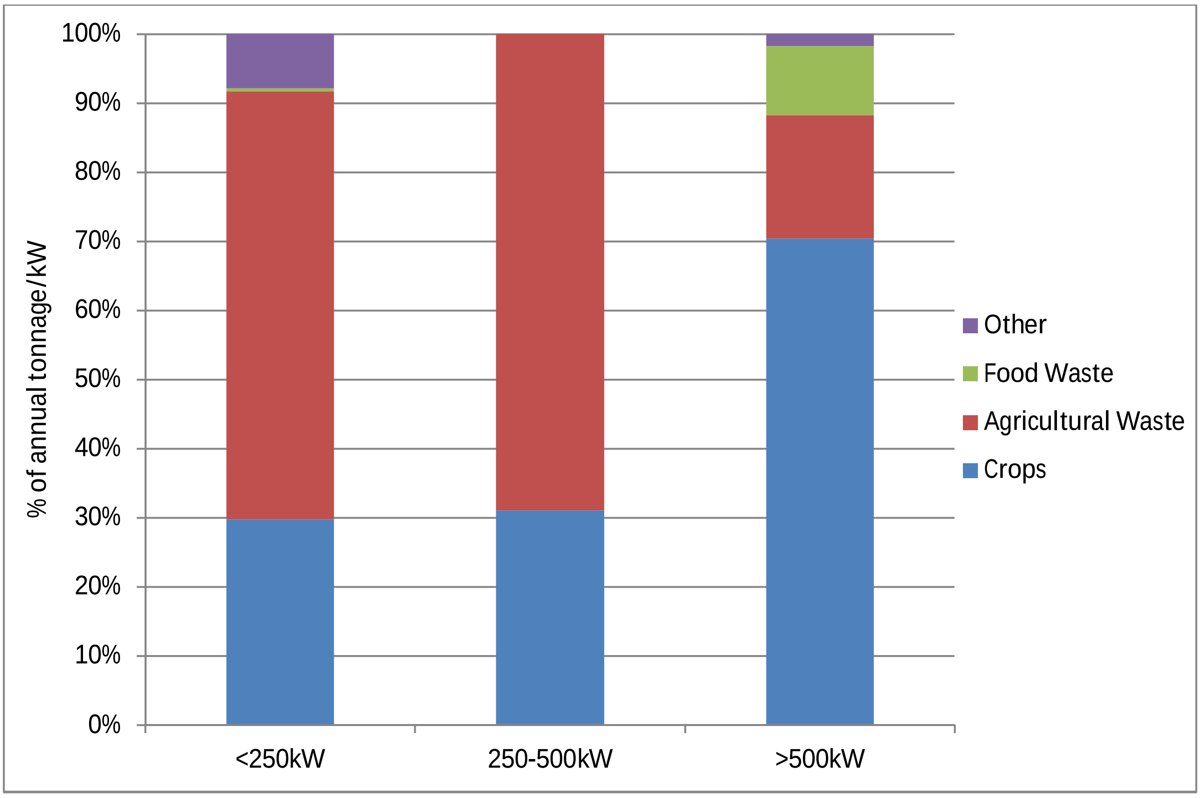

Figure 3:4 Average feedstock mix (tonnage per year) by capacity band assuming a typical project

3.3.1.8 In order to calculate the average feedstock cost for a typical project within each capacity band, the average annual tonnage/kW given by the questionnaire data and the typical feedstock cost (£/kW) given in the table above was used to determine an approximate feedstock cost per kW for each capacity band.

	Typical Feedstock Mix (tonnes/kW/year)				Typical Feedstock Cost/Gate Fee (£/kW/year)				
Capacity Band	**Crops**	**Agricultural Waste**	**Food Waste**	**Other**	**Crops**	**Agricultural Waste**	**Food Waste**	**Other**	**Total typical feedstock cost (£/kW/year)**
<250kW	6.36	13.92	0.25	4.17	163.24	69.6*	(10)	62.55	285.39
250-500kW	13.13	44.75	0	0	337.00	432.58	0	0	769.58
>500kW	13.20	4.00	2.20	0.40	338.80	38.67	(88)	14	303.47

*This value was calculated assuming that agricultural manure/slurry costs are £0 for plants of this size, given that they are typically plants located on farmland, where manure is a by-product of farming activities and is not a purpose bought feedstock.

3.3.1.9 These results suggest that AD plants <250kW typically have lower annual feedstock costs given that a large amount of their feedstock is agricultural waste which has lower feedstock costs attached to it (or is even free where plants utilise farming by-products like slurry). Plants in the central band have higher feedstock costs as they buy in large quantities of crops or agricultural products, but do not receive gate fees. As they are not typically owned by farmers (whereas <250kW are likely to be), they do not benefit from free by-products which can be used as feedstock. Plants >500kW typically benefit from offset feedstock costs given that they can process food waste and therefore benefit from gate fees.

3.4 Evolution of Feedstock Costs and Gate Fees – Anaerobic Digestion

3.4.1.1 The following section was compiled with assistance from WSP and discusses how feedstock costs and gate fees are likely to change with time.

3.4.1.2 Industry data available suggests that gate fees will fall in the immediate future and that the decrease in gate fees is already occurring. 'Average contracted and gate fee prices for food waste have shown a steady decline over the past two years'[14] in the face of growing competition for food waste to meet the increasing capacity of anaerobic digestion technology coming online. Site operators interviewed by *letsrecycle.com* suggested that gate fees of £20 and £10 have been seen, and that 'AD operators [are] offering to take in food waste for free in order to feed capacity'. In the same article, the Anaerobic Digestion and Bioresources Association are also quoted as saying that gate fees "continue to fall". Agrivert were also referenced as saying that some companies have dropped their spot gate fees for food waste to very low levels, but exact figures are not provided.

3.4.1.3 The WRAP Gate Fees report 2014 states that the median gate fee paid for food waste at AD facilities is £40 per tonne, slightly lower than the £41/tonne median value determined in 2013 and 2012. The WRAP Gate Fees report produced in 2013 also states that 'the general consensus amongst AD operators [is] that gate fees [are] likely to fall slightly over the coming years'[15], however the 2014 report states that 'the future direction of AD gate fees is uncertain with almost as many local authorities in this year's survey expecting an increase (37%) [as] those that answered the question as expecting a decrease (43%). 20% are expecting no change.'[16]

3.4.1.4 While the WRAP report contains much larger sample sizes and references all sources, it utilises data gathered from local authorities and as such, is not a full representation of all types of AD plants installed across the United Kingdom. Parsons Brinckerhoff approached WSP for further comment on the future of gate fees, who confirmed that they expect the average gate fee to fall in the future given that there is currently more food waste available than there is demand for.

3.4.1.5 A report produced by the National Non-Food Crops Centre (NNFCC) in 2011[17] which analyses the sensitivity of changing feedstock prices gives production costs of grass and maize at £24.85 and £28.95 respectively, which is in line with Parsons Brinckerhoff's average feedstock cost per tonne (2014 assumption) of £25 for grass and £28 for maize.

3.4.1.6 While there is little publicly available information that discusses the possible evolution of feedstock prices, Parsons Brinckerhoff predict that costs will fluctuate in the near

[14] Gate fees drop as AD operators scrap over food waste, 2015. Available at http://www.letsrecycle.com/news/latest-news/gate-fees-drop-as-ad-operators-scrap-over-food-waste/
[15] Gate Fees Report 2013 - Comparing the Costs of Alternative Waste Treatment Options, 2013. Available at http://www.wrap.org.uk/sites/files/wrap/Gate_Fees_Report_2013_h%20%282%29.pdf
[16] Comparing the Costs of Alternative Waste Treatment Options, 2013/2014. WRAP. Available through registration at http://www.wrap.org.uk/content/wrap-gate-fees-report-detailed-2014.
[17] Farm-scale Anaerobic Digestion Plant Efficiency, 2011. NNFCC. Available at http://www.swarmhub.co.uk/downloads/pdf/Farm_Scale_AD.pdf

future. As the number of plants and AD capacity coming online increases, the competition for feedstock from operators will grow and feedstock is likely to become more expensive. This could then lead to a tipping point where producing feedstock for AD is more profitable than crop production for the food industry (or likewise), driving increased production of feedstock from farmers with available land. Overproduction of feedstock would then lead to falling feedstock prices, but the extent of these fluctuations is hard to predict.

3.4.1.7 Within the questionnaire responses for <250kW plants, most respondents stated that their feedstock use was unlikely to change with time and that they didn't have a contract in place for their feedstock, suggesting that for smaller plants, the feedstock was produced as part of their farming (or other commercial industry) activities. One respondent did have contracts for their feedstock, with agricultural waste secure for 5 years and crops secure for 10.

3.4.1.8 The larger plants surveyed typically had contracts in place for feedstock with a 5 or 10 year lifetime. Of the responses relating to plants > 250kW, almost all stated that their feedstock type was likely to change with time, which represents a large future capital outlay relating to reconfiguring the plant for a different feedstock type.

3.5 Digestate Disposal – Anaerobic Digestion

3.5.1.1 Parsons Brinckerhoff questionnaire sought to collect data on digestate disposal costs for each capacity band which are shown in the table below. The data shows a range of values within each band. Note that digestate disposal costs have not been included within the Opex costs quoted within this report, however the analysis below provides some indication of typical disposal costs.

Capacity Band	Digestate disposal cost (£/year)
<250kW	2 data points: £0 1 data point: £5/ton[18] 1 data point: £7,000
250-500kW	10 data points: £0 1 data point: £3.50*[19] 1 data point: £180,000
>500kW	3 data points: no data provided 1 data point: £2*[20] 1 data point: £200,000

*assumed to be per ton, but no units provided by questionnaire respondents.

3.5.1.2 In the absence of digestate volume produced per annum for three of the data points received, we have produced some estimates of digestate disposal costs in the footnotes to the table above but these may not be accurate representations of typical disposal costs.

[18] Using tonnage of feedstock per year, estimated annual cost of £102,500.
[19] Using tonnage of feedstock per year, estimated annual cost of £37,275.
[20] Using tonnage of feedstock per year, estimated annual cost of £30,400.

3.5.1.3 The data suggests that for plants <500kW, digestate disposal costs are generally close to £0, possibly as operators of these plants use the digestate as part of their own farming (or other small industrial) activities or as revenues from selling digestate are cancelled out by transport costs. This is supported by WRAP's 2013 report into digestate distribution models[21]and their Anaerobic Digestate Financial Impact Assessment[22].

3.5.1.4 For plants >500kW, the two data points are equivalent to costs of £47/kW/yr and £71/kW/yr. In the absence of a larger dataset, the average of these values could be used i.e. £59/kW/yr. The higher costs for this band may be a result of larger plants that have more digestate to dispose of and so find it harder to achieve zero- or low-cost local disposal.

3.6 Anti-dumping scenarios – Solar PV

3.6.1.1 In June 2013, the European Commission announced that provisional anti-dumping duties would be imposed on imports of solar panels, cells and wafers from China. These duties were imposed as a way of ensuring fair and competitive prices across the countries of the EU in relation to the solar PV industry.

3.6.1.2 The anti-dumping duties were the result of an investigation that the Commission launched in 2012, in response to a complaint by the European Pro Sun coalition, a group of 25 European solar panel manufacturers headed by the German-based SolarWorld.

3.6.1.3 In December 2013, the European Council backed the proposal to impose anti-dumping and anti-subsidy measures on imports of solar panels from China. The duties were fixed at an average of 47.7% and would apply for two years as of 6 December 2013[23]. The pact covers more than 90 Chinese exporters that have about 60 percent of the EU solar-panel market. Participating producers include Yingli, Suntech, Trina, Jiangsu Aide Solar Energy Technology Co., Delsolar (Wujiang) Ltd., ERA Solar Co., Jiangsu Green Power PV Co. and Konca Solar Cell Co.

3.6.1.4 These duties ensure a "minimum price" for solar panels, cells and wafers is seen across Europe. The forecast Capex costs in Section 2 assume that the anti-dumping duties will remain in place and stable up to, or past, 2021.

3.6.1.5 DECC have requested that these Capex costs are also forecast assuming that the anti-dumping duties are revoked following review in December 2015 (with lower priced Chinese panels available for installation from January 2016).

3.6.1.6 The figures given in section 2.2 of this report assume that anti-dumping duties remain in place. The following calculations assume that anti-dumping measures are revoked in December 2015.

3.6.1.7 During the final quarter of 2014, it was estimated that the delivered price of Tier 1 modules from China were approximately USD0.57/W compared to the EU delivered

[21] Available at http://www.wrap.org.uk/sites/files/wrap/Digestate%20distribution%20models%20report.pdf
[22] Published 2009, Available at http://www.organics-recycling.org.uk/uploads/category1060/Financial_impact_assessment_for_anaerobic_digestate.pdf
[23] http://europa.eu/rapid/press-release_IP-13-1190_en.htm

price of USD0.65/W[24]. As the Chinese panels are subject to a 47.7% duty, it is reasonable to assume that relaxed anti-dumping laws would yield a delivered price of USD0.39/W (during the final quarter of 2014).

3.6.1.8 Parsons Brinckerhoff have retained the forecast linear decrease in PV panel costs in line with that demonstrated in the IRENA report and discussed in 2.2.5.1, but have assumed a scenario that from January 2016, all solar PV installations in the United Kingdom are built using Chinese panels imported free from the 47.7% duty. The balance of plant cost has not been changed as a relaxation of these duties would not affect this cost.

3.6.1.9 Using this methodology, the forecast Capex costs would be as follows:

Capacity Band	March 2015	Jan 2016	Jan 2017	Jan 2018	Jan 2019	Jan 2020	Jan 2021	Jan 2022
<4kW new build	1,688	1,426	1,409	1,392	1,376	1,360	1,344	1,328
<4kW retrofit	1,688	1,426	1,409	1,392	1,376	1,360	1,344	1,328
4 - 10kW new build	1,442	1,225	1,211	1,197	1,183	1,169	1,156	1,142
4 - 10kW retrofit	1,442	1,225	1,211	1,197	1,183	1,169	1,156	1,142
10 - 50kW new build	1,250	1,062	1,050	1,037	1,025	1,013	1,002	990
10 - 50kW retrofit	1,250	1,062	1,050	1,037	1,025	1,013	1,002	990
50-150kW new build	1,173	997	985	974	962	951	940	930
50-150kW retrofit	1,173	997	985	974	962	951	940	930
150-250kW new build	1,072	910	900	889	879	869	859	849
150-250kW retrofit	1,072	910	900	889	879	869	859	849
250-5000kW new build	1,021	868	858	848	838	828	819	809
250-5000kW retrofit	1,021	868	858	848	838	828	819	809
Stand alone	1,039	883	873	862	852	842	833	823
Agg <4	1,519	1,284	1,268	1,253	1,238	1,224	1,209	1,195
Agg >4	1,298	1,103	1,090	1,077	1,064	1,052	1,040	1,028

3.6.1.10 Figure 3:5 below shows the forecast Capex costs for solar PV assuming that anti-dumping duties are not relaxed in December 2015. This represents the base case.

[24] http://www.greentechmedia.com/articles/read/regional-pv-module-prices-vary-by-as-much-as-0.16-w

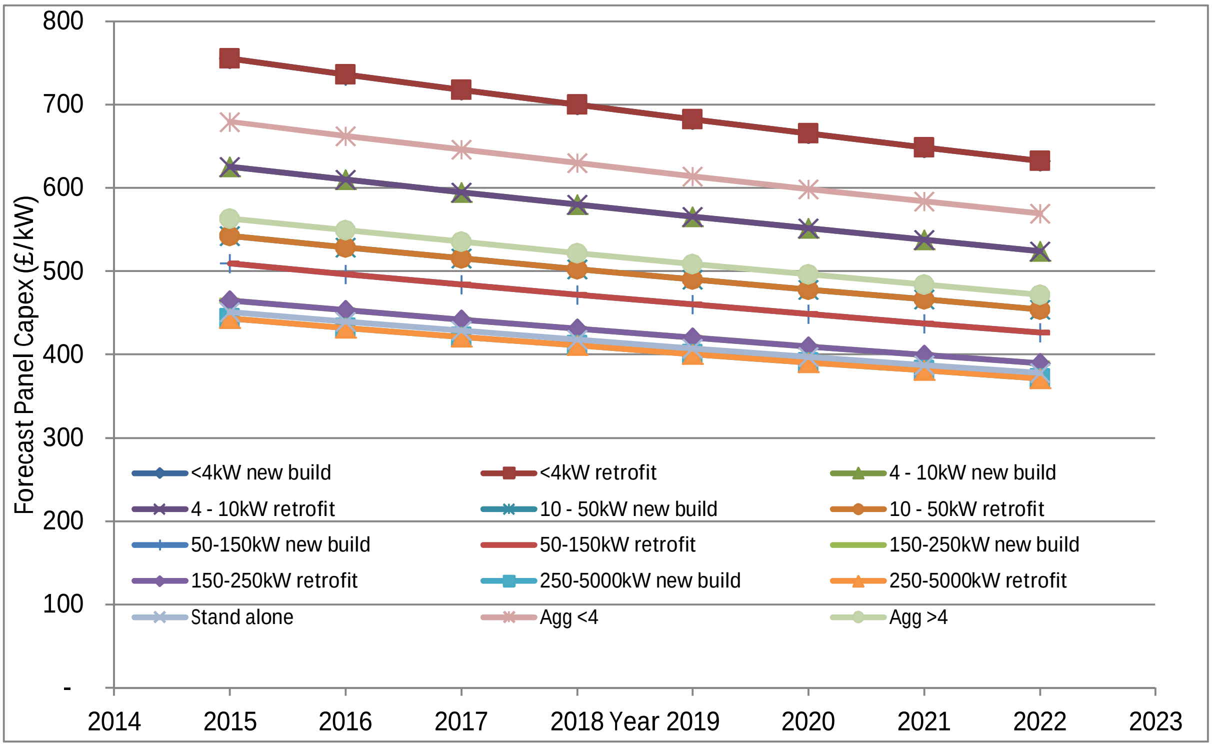

Figure 3:5 Forecast solar PV Panel Capex assuming anti-dumping duties are not relaxed

3.6.1.11 Figure 3:6 below shows the base case in relation to the "relaxation" scenario, with one system type displayed for simplicity. As shown, relaxation of the laws would trigger a sudden decrease in Capex costs as cheaper panels are available for installation. Over time, there would be gradual but minor convergence of the two cases as the panel price becomes a smaller percentage of the total Capex cost.

3.6.1.12 A more realistic, central case if anti-dumping measures were relaxed would probably lie between the two cases given below.

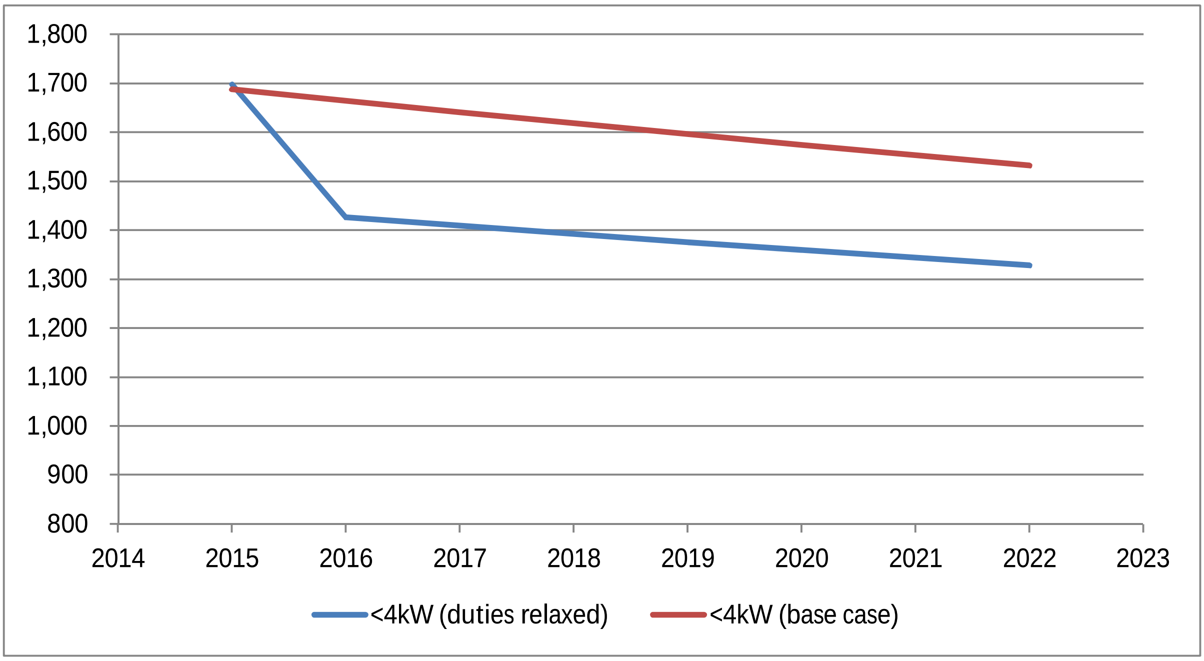

Figure 3:6 Forecast Capex for base case and relaxation case

4 QUALITATIVE ASSESSMENT

4.1 Introduction

4.1.1.1 In addition to the data-gathering exercise, all consultees were asked a number of questions in relation to the technologies covered by the FIT and their perception of the future of these markets and barriers to deployment. The following section discusses the issues raised and attempts to form a sector-wide view of the industry and its future challenges.

4.1.1.2 The following narrative represents views expressed in the questionnaire responses **only** and does not necessarily represent the views of DECC or Parsons Brinckerhoff.

4.2 Solar – domestic

When planning your solar PV installation, was it more important for you to do something that saved you money (through reduced energy bills/FIT), or that could benefit the environment? Why?

4.2.1.2 While domestic installers all stated the decision to install solar panels was based on a desire to benefit the environment, all respondents agreed that saving money was also an important factor and that both elements had to align. One homeowner acknowledged that their payback time was likely to be much longer than first anticipated, but a second homeowner stated that the FIT allows them to earn a better return on capital than current bank interest rates.

Any other comments?

4.2.1.3 One homeowner suggested a "fast FIT" scheme for commercial installations in order to boost the market, where a higher tariff is paid for a shorter length of time in order to speed up payback and increase return on investment, with a reduced FIT for the remainder of the plant's lifetime. This would help to unlock the commercial solar market and reduce financial risk.

4.3 Solar – commercial

4.3.1.1 Very few qualitative responses were received in relation to solar PV and the views outlined below reflect those responses received. Attempts to obtain additional information in relation to the following questions were often passed over by stakeholders.

How do you see the solar PV market changing over the next 5 years?

4.3.1.2 Commercial solar developers discussed the recent move from RO to CfDs and the indirect impact that this will have on FIT customers. The understanding is that as solar (with a cost of $157/MWh) has been grouped with onshore wind (with a cost of $88/MWh), solar has now become non-competitive in the CfD scheme. This will in turn reduce the deployment of large-scale solar PV arrays, which could stall the development of the technology, reducing the opportunity for cost reduction of the technology, materials and equipment. As cost reductions in the large scale market feed into the domestic and FIT markets, all will suffer.

4.3.1.3 A number of additional stakeholders also explained to Parsons Brinckerhoff and DECC that the solar PV market in the UK was rapidly moving towards a subsidy free future, with grid parity reached in 2018-2020.

What is your opinion on site availability? Are suitable sites still available for development?

4.3.1.4 Developer consultees agree that solar PV is one of the least controversial forms of energy production in the UK and should be encouraged, but that FIT tariff banding has made ground-mounted sites unattractive and not financially viable. While rooftop sites are available, the number of suitable sites is finite.

4.4 Wind

How do you see the onshore wind market changing over the next 5 years?

4.4.1.2 Technology manufacturers and project developers agree that the market will shift, but disagree with regards to which direction. While some respondents believe that the onshore wind market will become more reliant on small scale/micro generation with a smaller visual impact, deployed in greater numbers for distributed generation, others believe the market will shift towards larger turbines with a lower cost of energy. One manufacturer and a number of developers suggested that the market will diminish to very low levels due to the lack of viable incentives and a second stated that with an ongoing tariff degression of ~20% per year, the market is expected to effectively die in the very near future without intervention. Grid capacity, especially for turbine developments above 50kW, was highlighted as a roadblock across most parts of the country with a suggestion that attention should be given towards supporting the commercial development of energy storage technologies – an idea supported by developers.

4.4.1.3 Developers suggested that with the current degression levels, a future for small to medium scale projects between 500kW and 20MW looks unlikely. Discussion touched on investment in the wind industry and the difficulties in selling projects to investors if the FIT rate drops below the current levels as investors will look elsewhere for higher yields. Consolidation of companies in the industry as the market tightens and henceforth a notable shrinkage of the industry was also suggested by a number of consultees, making achieving 2030 decarbonisation targets more difficult.

4.4.1.4 Developers and non-domestic respondents both suggested that community ownership could become more prevalent, especially in relation to single turbine sites with a high energy usage or near small settlements. However, a second developer viewed that the continuous FIT degression makes progressing further single turbine and small cluster projects challenging when the greatest remaining potential in the UK is for these types of developments. Expansion or repowering upgrades of existing wind farms may take place instead of the development of new sites.

4.4.1.5 Developers discussed how the tariff bands do not best reflect available technology, resulting in a number of single turbine projects having to be de-rated in order to make them viable.

Would you have installed a higher capacity turbine(s) at any of your sites if the tariff banding was structured differently? If yes, at which site(s)? What capacity would you have installed?

4.4.1.6 Opinion was split equally in response to this question. While a community consultee confirmed that they would not have installed a higher capacity turbine as they had to “live with” their project and would not want a taller turbine, a non-domestic respondent stated they would have installed a 900kW or 1.5kW turbine in place of their 500kW if the tariff bands were structured differently.

4.4.1.7 Responses to this question were largely site specific – for lower wind speed sites, developers would install larger turbines or more than one turbine, although high capital costs make it difficult to do in every case. One developer said they would not change any of the sites they had previously developed, but would have to install larger turbines on any new sites in order to make their projects economically viable. However, one developer disagreed and stated that banding should favour micro generation as this supports the many, not the minority.

4.4.1.8 A number of responses mentioned projects with an installed capacity of 500kW, stating that higher capacity turbines would have been installed on these sites had there been higher tariffs available. One manufacturer and developer discussed in detail how schemes are developed at the upper ends of the capacity bands as defined by the FIT, which then results in turbine manufacturers manufacturing turbines sized specifically for the upper ends of the bands (500kW and 1.5MW). Developers also push projects to the high ends of these bands to ensure least risk and higher returns. This was reflected in the data gathered under this project with a large number of projects with an installed capacity of 500kW.

What is your opinion on site availability? Are suitable sites still available for development?

4.4.1.9 The majority of consultees agreed that sites are becoming more difficult to find with high enough wind speeds (7.0 – 7.5m/s) to hit the hurdle rates required, with grid availability and without aviation radar constraints. Where sites are available, smaller chances of getting through planning and increasing pressure on landowners from anti-wind groups contribute to fewer planning applications being submitted. A community consultee confirmed that their recent experience showed that most sites have already been surveyed with options to develop already secured and that new sites are very difficult to find.

4.4.1.10 The lack of available grid capacity was discussed in detail, as for hydro above. Some suggestions were made that micro generation may be the only way forward as the constraints are less limiting.

4.4.1.11 A group of consultees agreed that suitable sites were available although the degression of the FIT makes it financially unattractive for potential owners to develop the sites. One respondent suggested that grid upgrades, aviation improvements and increased community involvement had the potential to open up more sites in the future, potentially for single and small cluster developments.

How do you see hurdle rates evolving over the next five years?

4.4.1.12 All respondents agreed that hurdle rates will fall over the next five years, although the exact percentage they will fall to was not discussed. Manufacturers and developers suggested they would reduce by a “couple of percent” and that they would need to decrease in order for them to continue to work in the market. Respondents stated that the reduction in these hurdle rates (especially if combined with an increase in interest rates) would cause investors to leave the space, a huge reduction in the number of planning applications and/or a complete cease in the development of new sites and the potential demise of the small wind industry.

4.4.1.13 A non-domestic respondent suggested that hurdle rates would decrease given emerging funding methods, such as crowdfunding. A community respondent confirmed that developers and investors will need to accept lower returns if they are to continue developing turbines onshore.

4.4.1.14 Parsons Brinckerhoff believes that some of these responses discuss 'hurdle rates' where 'return on investment' should instead be used.

How do project constraints or cost/financing implications vary across community-led/shared ownership projects and commercial projects?

4.4.1.15 Responses to this question were largely in agreement to those given in relation to community hydro projects. Developers confirmed that community partnership projects are considerably more time consuming to develop and that funding is difficult to secure. However, as for wind, no real evidence was provided as part of this data collection exercise that suggested community projects had higher capital or operating costs than commercial or developer led projects.

4.4.1.16 Shared, or community ownership schemes are not considered attractive by FIT developers due to the up-front costs of involving the community prior to achieving consent, when there is no guarantee that community support will help achieve consent and solely community-owned schemes may have difficulties raising capital and navigating the planning and construction phases of the development. Generally, commercial projects will move through the planning and feasibility stages of the project much faster.

Any other comments?

4.4.1.17 One developer suggested that the <500kW FIT band is too generous, with the >1.5MW band unviable since the first degression. Adjustments of these bands would ensure a sensible long-term future for the onshore FIT wind market. Other respondents disagreed, stating that the removal of the 15kW banding following the previous consultation has resulted in an 80% decline in micro-generation installations and that as turbines >50kW do not have to go through product certification and can be pre-accredited, the sub <50kW market is being heavily penalised with no FIT adjustment to compensate for this. It was also highlighted that 80% of microgeneration turbines installed in the UK were manufactured in the UK, whereas 90% of >50kW turbines installed in the UK were imported, and that a tariff change is needed in order to support the UK manufacturing industry.

4.5 Hydro

How do you see the hydroelectric market changing over the next 5 years?

4.5.1.2 Domestic respondents to this survey agreed that further cuts in the FIT would affect further uptake in this technology, but disagreed over the future Capex costs relation to hydro – while one domestic consultee suggested that technology improvements would make systems easier and cheaper to install, another discussed the lack of economies of scale relating to hydro installations, and how rising material and labour costs do not corroborate with tariff degression. Domestic respondents also touched on the deterring element of high development and planning costs and the regulations imposed by the Environment Agency around hydro generation, calling them "restrictive and unsubstantiated".

4.5.1.3 Non-domestic respondents were largely in agreement about the future of the hydroelectric market, suggesting that the market may not improve with the reduction in the FIT, increasingly challenging regulations and limited future cost reductions in the technology. They agreed that there is always likely to be some demand for the technology, but that any further reduction in the FIT will limit the construction of future schemes.

4.5.1.4 Developers varied in their responses to this question. While some developers suggested that the market has slowed in the last 12 months and the level of new enquiries has fallen dramatically, others suggested that the FIT has been generally positive for hydro – stimulating investment without over-compensating investors. Almost all developers were in agreement that the degression mechanism will significantly curtail, or potentially collapse future deployment and that this has been witnessed in the small, domestic scale projects (<15kW). Regulatory barriers from the Environment Agency (EA) and inflation have increased the capital costs of hydro as the FIT has decreased and the decreasing interest in early stage development since 2014 is a result of this.

4.5.1.5 Developers also suggested that 2015 and 2016 may see an unprecedented boom in construction, with up to 40MW deployed each year but following that, construction will fall dramatically, returning to pre-FIT levels of deployment. Largely, hydro will fall way short of its deployment potential given a lack of funding sources, degression rates based on pre-accreditation and lack of build out and a suggested bias towards other renewable energy technologies.

4.5.1.6 Utility scale respondents agreed that a surge of construction in the coming years is likely, but FIT degression will ensure that very few < 5MW sites will be developed beyond 2018.

4.5.1.7 Specialist consultancies who were approached during this study suggested that the market would see a move towards a larger number of community projects. Respondents also stated that while micro-hydro (<100kW) has enormous potential across the UK, the levels of bureaucracy in place restrict uptake and limit interest from commercial manufacturers and installers.

What is your opinion on site availability? Are suitable sites still available for development?

4.5.1.8 Domestic respondents agreed that there are thousands of sites still available, particularly on old mill sites, but that many are difficult to develop. The comments from non-domestic respondents echoed these thoughts by confirming that there are plenty of small (<100kW) sites still available, but that most are un-economic to develop, possibly as a result of high consenting costs, and are restricted by EA data requirements and reduced permissible water flows.

4.5.1.9 Comments from developers agreed that a substantial number of technically viable sites are still available, but that FIT degression has pushed the marginal ones out of range and the feasibility of identified opportunities is dependent upon adequate support mechanisms being in place. A key comment raised by many respondents relates to the grid and the lack of cohesion between grid connection dates and the two year FIT build window. Of the sites that are yet to be exploited, many lie in areas with severe grid constraints where upgrades are planned but would not be complete in time for connection under the FIT mechanism. Some developers also discussed their lack of confidence in the FIT regime affecting their willingness to develop further sites. However, one developer did confirm that viable sites are still available at the current FIT levels, but that viability significantly decreases once total degression in FIT rates exceeds 20%.

4.5.1.10 Utility-scale respondents largely agreed with these views and confirmed that they own a development pipeline of schemes, however unless an improvement in support mechanisms happened, it is unlikely they would be constructed.

How do you see hurdle rates evolving over the next 5 years?

4.5.1.11 Developers were largely in agreements that the hurdle rates are already as low as viable and will only increase as the cost of finance increases. 8% was given as the minimum return on equity required by professional investors with a view that this will not evolve significantly over the next 5 years unless slightly upwards as projects become more challenging and investment is instead made into other industries with a more attractive risk/reward profile. Another respondent suggested that as interest rates are currently at a historical low, it seems inevitable that they will only rise again in years to come, but that the cost of finance for small-scale hydro is not comparatively low. It was suggested in the responses that tariff degression has taken FIT levels to a point where it is not possible to meet existing hurdle rates, hence the cessation of new project development. As hydro is civil engineering led, technology improvements will have little impact on the cost of installation and therefore big changes in finance required is unlikely.

4.5.1.12 A consultant respondent agreed with the views of the developers and suggested that hurdle rates for many schemes are now on the threshold of private funding.

4.5.1.13 Parsons Brinckerhoff believes that some of these responses discuss ‘hurdle rates’ where ‘return on investment’ should instead be used.

How do project constraints or cost/financing implications vary across community-led/shared ownership projects and commercial projects?

4.5.1.14 Developers largely agreed that it is dependent on the source of funding. If self-investment or low cost funding is available for community schemes, they can develop projects with lower hurdle rates. While community projects may appear easier to develop, it is perceived that they seriously underperform in comparison to commercial projects, and for a given project, a community-led approach will generally be more expensive, more complex, will take longer and be riskier than the same project led by a commercial developer. However, the respondents concluded that community and commercial schemes are facing the same challenges – obtaining finance, FIT degression, the pressures of a 2 year build window, grid availability and contractor availability during the short-term construction ‘boom’ resulting from the pre-accreditation/degression effect. One developer noted that while there is an impression that a wave of new money has entered the hydro sector, this is primarily equity finance which is not what communities or commercial developers are seeking.

4.5.1.15 A consultant believed that project IRRs are becoming too low for most commercial investments and as such, ‘low-return’ community schemes could become the norm in future. A non-domestic respondent explained that for community projects, it is more difficult to obtain the initial high-risk financing for development works and agreed with the developers that hydropower is a challenging technology for community organisations to develop; however, it was suggested that local authorities may be ideally placed to develop schemes as they have both land availability and sources of capital.

4.5.1.16 Generally, no real evidence was provided as part of this data collection exercise that suggested community projects had higher capital or operating costs than commercial or developer led projects.

Any other comments?

4.5.1.17 One domestic respondent suggested that the FIT payments should be stepped by number of units produced rather than installed capacity in order to encourage owners to produce the maximum units they can. Suggestions were also made to change the EA regulations in order to make them more flexible and site-specific.

4.5.1.18 Developer responses suggested that while hydro faces a cliff edge at the end of 2016, there is a similar situation present for all renewable energy sectors whereby a false impression is being given by what is happening at the construction end of the development pipeline. Focus should instead be fixed on the other end of the pipeline with sufficient encouragement given to stimulate the speculative investment that is necessary if the growth in renewable technologies is to continue.

4.5.1.19 Consultant respondents suggested that small (<15kW) self-funded domestic schemes are likely to stop being installed at all, and that <10kW are currently no longer financially viable for the majority of sites. A utility respondent also commented that taxes relating to hydro projects will be elevated by the lack of any tax relief on substantial proportions of capital expenditure.

4.6 Anaerobic Digestion (AD)

How do you see the anaerobic digestion market changing over the next 5 years?

4.6.1.2 Respondents were concerned by a lack of tariff certainty (and quick tariff degression) and the impact this has had on availability of funding for the projects. Respondents felt this was a particular issue for sub 500kW systems and was having an impact on mixed agricultural waste and crop input systems for farms. One respondent noted that larger-scale, waste based projects may remain viable in the short term. This same respondent noted that tariff degression to date has proceeded at a faster rate than any reduction in project costs or required return rates.

4.6.1.3 One respondent raised grid constraints as a major issue for the future development of the CHP based AD market, and noted that restricted export to the grid meant projects could not be funded. The same respondent commented that FIT rates need to be adequate to compensate for restricted generation (ie. only exporting at night and during the winter) when it could act as a balancing mechanism for solar PV.

4.6.1.4 One respondent noted the oversupply of digesters and shortage of feedstock as a key issue for market development.

4.6.1.5 One respondent noted that downward pressure on gate fees is likely to constrain growth in the market in the medium term.

How do you see the gate fee market evolving over the next 5 years?

4.6.1.6 The general consensus of respondents was that the gate fee market will fall significantly, and will ultimately be a cost rather than an income for the projects.

4.6.1.7 One respondent attributed the fall in gate fees to certain areas having overcapacity of processing sites, slow progress on capture rates and delay in introducing a ban on food waste to landfill.

4.6.1.8 One respondent noted that their expectation was that the food waste gate price will drop through competition to less than £15 per tonne and any additional charges will be commensurate with the level of de-packaging or process difficulty associated with it.

How secure is your current feedstock supply? Do you foresee any problems with availability? How do you think feedstock usage across the market will change over the next 5 years?

4.6.1.9 The general consensus from respondents was that agricultural feedstock is secure as it's produced by local livestock and grown on the farm and farm-based AD can take advantage of market oversupply which are readily available at a low gate price. Security of the overall feedstock ranged from very secure to partially secure.

4.6.1.10 One respondent noted that for projects that use waste feedstocks, long term supply contracts are increasingly difficult to obtain, meaning that project risks are increased which has increased the hurdle rate.

How do you see hurdle rates evolving over the next 5 years?

4.6.1.11 Responses to this question varied slightly but the general content is summarized below:

- The hurdle rate is unlikely to change;
- The hurdle rate is unlikely to drop significantly due to the operational complexity of AD projects and the risks around feedstock supply and digestate disposal;
- In the near term, hurdle rates may actually increase due to the removal of relatively low cost Enterprise Investment Scheme and Venture Capital Trusts funding from the market;
- Debt finance will become harder to secure as some projects fail due to lack of feedstock and technical problems;
- Investors will always look for the maximum return.

4.6.1.12 One respondent noted that farm systems with a higher level of equity or asset recourse are more influenced by overall estate / farm sustainability and long term financial requirements, however the current degression of the FIT and uncertainty on the Renewable Heat Incentive has meant that these systems may not currently be viable.

Any other comments?

4.6.1.13 One respondent noted that although there is still a great deal of interest in the AD sector, very few projects are now managing to get funding. In many cases the initial farm based plants are requiring substantial adjustments to meet the permit requirement which were not made clear in the initial delivery by the technology suppliers, as the farmers were not used to the requirements of the waste permitting side.

4.6.1.14 The same respondent noted that feedstock costs have also in most cases exceeded what was initially envisaged as has the level of management for farm scale systems and it may be that some of the current plants do not achieve (by a significant margin) the 20 year operational plan. There are many excellent farm scale plants that are run by dedicated and informed individuals who are clear that if the opportunity was to come up again with the current degression that they would not go down the AD route in the current climate.

ANNEX A – WEIGHTINGS

Solar Capex

Year Installed		
2012	0.7	Somewhat higher Feed-in Tariffs available during these years means Capex prices were also skewed to ensure an 8-10 year payback period.
2013	0.8	
2014	1.0	
2015	1.0	
Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	
Example	0.8-1.2	Adjusted upwards or downwards by 20% depending on Parsons Brinkerhoff's view of how realistic estimated prices are.

Solar Opex

Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	
Example	0.5	Sources provided examples were largely unsure of Opex prices as projects are often transferred once commissioned.

Wind Capex

Year Installed		
2010	0.85	Weighted reflective of the higher project costs prior to December 2012.
2011	0.85	
2012	0.85	
2013	0.95	Weighted reflective of the higher project costs prior to 2014.
2014	1.0	
2015	1.0	
Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	
Example/Anticipated	0.9-1.1	Adjusted upwards or downwards by 10% depending on Parsons Brinkerhoff's view of how realistic estimated prices are.

Wind Opex

Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	
Example	0.95-1.05	Sources provided examples were largely unsure of Opex prices as projects are often transferred once commissioned.

Hydro Capex

Year Installed		
2010	1.05	Adjusted due to the lower FIT rate prior to 2012.
2011	1.05	
2012	1.05	
2013	1.0	
2014	1.0	
2015	1.0	
2016	1.0	
2017	0.95	Adjusted for uncertainty around predicted costs.
Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	
Example	0.8-1.2	Adjusted upwards or downwards by 20% depending on Parsons Brinkerhoff's view of how realistic estimated prices are.

Hydro Opex

Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	
Example	0.5	Sources provided examples were largely unsure of Opex prices as projects are often transferred once commissioned.

Anaerobic Digestion Capex

Year Installed		
2009	1.0	
2010	1.0	
2011	0.9	Adjusted to reflect increased project costs during this period.
2012	0.75	
2013	0.75	
2014	1.0	
2015	1.0	
Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	
Example	0.8-1.2	Adjusted upwards or downwards by 20% depending on Parsons Brinkerhoff's view of how realistic estimated prices are.

Anaerobic Digestion Opex

Data Source		
Domestic Homeowner	1.0	Unlikely to invest in further projects and as such, data source is likely to be accurate.
Community Group	1.0	
Other	0.95	Adjusted for bias.
Project Type		
Existing/Built	1.0	

ANNEX B – QUESTIONNAIRES

PARSONS BRINCKERHOFF

ONSHORE WIND

Name	
Company	
Email	
Telephone	
Company Type	

If required, Parsons Brinckerhoff will keep your responses anonymous.

Notes for completion of questionnaire

1. Please provide all costs as they were at the time they were incurred and do not adjust for inflation, but please state the year in which they were incurred. In other words, please express costs in real money terms of the year in which you incurred them. If you prefer to provide nominal costs (i.e. costs expressed in today's terms), please state the base year and which price index you are linking to (i.e. RPI, CPI, etc), either by adding a comment to the cell or by using the comment box at the bottom of this page.
2. Rural projects are defined as those that are in open and exposed areas which are largely free of obstacles in all directions. Urban sites are within built-up areas and are likely to be quite close to buildings and other ground features.
3. Installation (CAPEX) costs should include the design, procurement and construction costs (e.g. EPC costs) and equipment and civil works costs. They should NOT include owner's costs, grid connection costs or substation and/or transformer costs.
4. Installation cost should be the cost at date commissioned.
5. Grid connection costs should include any upfront connection payment and substation/transformer costs but exclude pre-connection securities.
6. OPEX costs should include labour, planned maintenance and lifecycle replacement. They should not include land costs, property and business rates tax costs, rental and community benefit payments. Variable OPEX may also include water and/or chemical usage.
7. Export fraction is the average annual fraction of electricity generated by the project and exported to the grid.
8. The 'hurdle rate' is the minimum expected project Internal Rate of Return (IRR) for investment in a generation asset realised over the life of the asset, at which investors will make a decision to proceed with the investment. Our preference would be to obtain this on a real, pre-tax basis; however should you chose to provide it on a nominal and/or post-tax basis, please indicate so either by adding a comment to the cell or by using the comment box at the bottom of this page.
9. 'Gearing' is defined as the proportion of debt in the project's capital structure; in other words it is the percentage of total project costs that is funded by debt.
10. The 'effective' tax rate is the implied tax rate on a project after accounting for the debt interest tax shield (if relevant) and capital allowances.
11. Please add more columns or rows to tables as necessary.
12. If you wish to clarify any of your answers, please use the comments box at the bottom of this page.

TECHNICAL ANALYSIS

	Project									
	1	2	3	4	5	6	7	8	9	10
Project Type										
Installed capacity (kW)										
Date commissioned										
Installation Cost (CAPEX) (£/kWp)										
inc. VAT? (Y/N)										
Landownership type										
CAPEX costs pertaining to land (i.e. purchase cost/total land rental during construction) (£/kW)										
Grid connection costs (£)										
Grid connection type										
Distance from project to grid connection (km)										
Turbine cost excl. VAT (£)										
Tubine Manufacturer/Model										
Hub height above Ground Level (m)										
Rotor diameter (m)										
Building mounted or mast mounted?										
Fixed maintentance (OPEX) (£/kW/yr)										
Variable maintentance (OPEX) (£/kWh)										
If site is leased/rented, what are annual land costs? (£/kW)										
Connection Use of System charges (£/kW/yr)										
Where is the site located?										
What is the site postcode?										
What is the average wind speed on site?										
Load Factor (%) - predicted										
Load Factor (%) - actual										
Export Fraction (%)										
Have you signed a PPA agreement for the project?										
If yes, what rate do you sell to the grid at? (p/kWh)										

ECONOMIC ANALYSIS

	Project									
	1	2	3	4	5	6	7	8	9	10
What is your hurdle rate for this investment? (%)										
What is the gearing of this project? (%)										
What is the cost of the debt? (%)										
What is your required return on equity? (%)										
What is the tenor of loan on this investment? (years)										
What risks do you see as the main drivers for the decision to invest (or not) in this technology?										
What is the useful project life of this investment? (Useful economic life for valuation purposes) (years)										
What is your effective tax rate? (%)										

FURTHER COMMENTS

How do you see the onshore wind market changing over the next 5 years?

Would you have installed a higher capacity turbine(s) at any of your sites if the tariff banding was structured differently? If yes, at which site(s)? What capacity would you have inst

What is your opinion on site availability? Are suitable sites still available for development?

How do you see hurdle rates evolving over the next 5 years?

How do project constraints or cost/financing implications vary across community-led/shared ownership projects and commercial projects?

Any other comments?

PARSONS BRINCKERHOFF

SOLAR PV

Name	
Company	
Email	
Telephone	
Company Type	

If required, Parsons Brinckerhoff will keep your responses anonymous.

Notes for completion of questionnaire

1. Please provide all costs as they were at the time they were incurred and do not adjust for inflation, but please state the year in which they were incurred. In other words, please express costs in real money terms of the year in which you incurred them. If you prefer to provide nominal costs (i.e. costs expressed in today's terms), please state the base year and which price index you are linking to (i.e. RPI, CPI, etc), either by adding a comment to the cell or by using the comment box at the bottom of this page.
2. For roof mounted solar, 'new build' should be selected as project type where panels were installed during the building of the house. 'Retrofit' should be chosen where panels were installed on the house at a later date.
3. A solar 'aggregator' is that defined as an organisation that develops/owns a large number of small projects that are treated as individual schemes under the FiT. If providing details on an 'aggregator' type project, please input costs as for the small, individual projects, not for the portfolio of projects as a whole.
4. 'Building integrated PV' should be completed where photovoltaic materials have been used to replace conventional building materials in a structure (e.g. roof, skylights). This does NOT include roof mounted solar PV.
5. Installation (CAPEX) costs should include the design, procurement and construction costs (e.g. EPC costs) and equipment and civil works costs. They should NOT include owner's costs, grid connection costs or substation and/or transformer costs.
6. Installation cost (CAPEX) should be the cost at date commissioned.
7. Grid connection costs should include any upfront connection payment and substation/transformer costs but exclude pre-connection securities.
8. OPEX costs should include labour, planned maintenance and lifecycle replacement. They should NOT include land costs, property and business rates tax costs, rental and community benefit payments. Variable OPEX may also include water and/or chemical usage.
9. Export fraction is the average annual fraction of electricity generated by the project and exported to the grid.
10. The 'hurdle rate' is the minimum expected project Internal Rate of Return (IRR) for investment in a generation asset realised over the life of the asset, at which investors will make a decision to proceed with the investment. Our preference would be to obtain this on a real, pre-tax basis; however should you chose to provide it on a nominal and/or post-tax basis, please indicate so either by adding a comment to the cell or by using the comment box at the bottom of this page.
11. 'Gearing' is defined as the proportion of debt in the project's capital structure; in other words it is the percentage of total project costs that is funded by debt.
12. The 'effective' tax rate is the implied tax rate on a project after accounting for the debt interest tax shield (if relevant) and capital allowances.
13. Please add more columns or rows to tables as necessary.
14. If you wish to clarify any of your answers, please use the comments box at the bottom of this page.

TECHNICAL ANALYSIS

	Project									
	1	2	3	4	5	6	7	8	9	10
Project Type										
Installed capacity (kW)										
Date commissioned										
Installation Cost (CAPEX) (£/kWp)										
inc. VAT? (Y/N)										
Landownership type										
CAPEX costs pertaining to land (i.e. purchase cost/total land rental during construction) (£/kW)										
Grid connection costs (£)										
Grid connection type										
Where is the site located?										
Distance from project to grid connection (km)										
Fixed maintenance (OPEX) (£/kW/yr)										
Variable maintenance (OPEX) (£/kWh)										
If site is leased/rented, what are annual land costs? (£/kW)										
Connection Use of System charges (£/kW/yr)										
Panel Cost excl. VAT (£/kWp)										
Panel Type (manufacturer/model)										
Inverter Cost excl. VAT (£/kWp)										
Inverter Type (manufacturer/model)										
Load factor (%) - predicted										
Load factor (%) - actual										
Performance ratio - predicted										
Performance ratio - actual										
Export Fraction (%)										
Have you signed a PPA agreement for the project?										
If yes, what rate do you sell to the grid at? (p/kWh)										

ECONOMIC ANALYSIS

	Project									
	1	2	3	4	5	6	7	8	9	10
What is your hurdle rate for this investment? (%)										
What is the gearing of this project? (%)										
What is the cost of the debt? (%)										
What is your required return on equity? (%)										
What is the tenor of loan on this investment? (years)										
What risks do you see as the main drivers for the decision to invest (or not) in this technology?										
What is the useful project life of this investment? (Useful economic life for valuation purposes) (years)										
What is your effective tax rate? (%)										

FURTHER COMMENTS

How do you see the solar PV market changing over the next 5 years?

What is your opinion on site availability? Are suitable sites still available for development?

How do you see hurdle rates evolving over the next 5 years?

How do project constraints or cost/financing implications vary across community-led/shared ownership projects and commercial projects?

Any other comments?

PARSONS BRINCKERHOFF

ANAEROBIC DIGESTION

Name	
Company	
Email	
Telephone	
Company Type	

If required, Parsons Brinckerhoff will keep your responses anonymous. .

Notes for completion of questionnaire

1. Please provide all costs as they were at the time they were incurred and do not adjust for inflation, but please state the year in which they were incurred. In other words, please express costs in real money terms of the year in which you incurred them. If you prefer to provide nominal costs (i.e. costs expressed in today's terms), please state the base year and which price index you are linking to (i.e. RPI, CPI, etc), either by adding a comment to the cell or by using the comment box at the bottom of this page.
2. Installation (CAPEX) costs should include the design, procurement and construction costs (e.g. EPC costs) and equipment and civil works costs. They should NOT include owner's costs, grid connection costs or substation and/or transformer costs.
3. Installation cost should be the cost at date commissioned.
4. Grid connection costs should include any upfront connection payment and substation/transformer costs but exclude pre-connection securities.
5. OPEX costs should include labour, planned maintenance and lifecycle replacement. They should NOT include land costs, property and business rates tax costs, rental and community benefit payments. Variable OPEX may also include water and/or chemical usage.
6. OPEX costs should not include feedstock costs or gate fees.
7. Feedstock cost should be presented as a negative number if it is a gate fee.
8. Export fraction is the average annual fraction of electricity generated by the project and exported to the grid.
9. The 'hurdle rate' is the minimum expected project Internal Rate of Return (IRR) for investment in a generation asset realised over the life of the asset, at which investors will make a decision to proceed with the investment. Our preference would be to obtain this on a real, pre-tax basis; however should you chose to provide it on a nominal and/or post-tax basis, please indicate so either by adding a comment to the cell or by using the comment box at the bottom of this page.
10. 'Gearing' is defined as the proportion of debt in the project's capital structure; in other words it is the percentage of total project costs that is funded by debt.
11. The 'effective' tax rate is the implied tax rate on a project after accounting for the debt interest tax shield (if relevant) and capital allowances.
12. Please add more columns or rows to tables as necessary.
13. If you wish to clarify any of your answers, please use the comments box at the bottom of this page.

TECHNICAL ANALYSIS

	Facility				
	1	2	3	4	5
Capacity (kW)					
Date commissioned					
Installation cost (CAPEX) (£/kWp)					
incl. VAT? (Y/N)					
Landownership type					
CAPEX costs pertaining to land (i.e. purchase cost/total land rental during construction) (£/kW)					
Grid connection costs (£)					
Grid connection type					
Where is the site located?					
Distance from project to grid connection (km)					
Fixed maintentance (OPEX) (£/kW/yr)					
Variable maintenance (OPEX) (£/kWh)					
If site is leased/rented, what are annual land costs? (£/kW)					
Connection Use of System charges (£/kW/yr)					
Feedstock Type #1					
Feedstock #1 cost/gate fee (£/tonne)					
Feedstock #1 use (tonnes/yr)					
Is feedstock use likely to change with time?					
Is there a contract for the feedstock?					
What is the length of the contract?					
Feedstock Type #2					
Feedstock #2 cost/gate fee (£/tonne)					
Feedstock #2 use (tonnes/yr)					
Is feedstock use likely to change with time?					
Is there a contract for the feedstock?					
What is the length of the contract?					
Feedstock Type #3					
Feedstock #3 cost/gate fee (£/tonne)					
Feedstock #3 use (tonnes/yr)					
Is feedstock use likely to change with time?					
Is there a contract for the feedstock?					
What is the length of the contract?					
Digestate disposal costs/income (£/yr)					
Load factor (%) - predicted					
Load factor (%) - actual					
Electrical efficiency (%)					
Export fraction (%)					
Have you signed a PPA agreement for the project?					
If yes, what rate do you sell to the grid at? (p/kWh)					
Engine manufacturer and model					
Is project receiving income from RHI?					
If yes, how much useful heat is generated? (kWth/yr)					
If yes, what is the expected revenue from RHI? (£/yr)					

ECONOMIC ANALYSIS

	Facility				
	1	2	3	4	5
What is your hurdle rate for this investment? (%)					
What is the gearing of this project? (%)					
What is the cost of the debt? (%)					
What is your required return on equity? (%)					
What is the tenor of loan on this investment? (years)					
What risks do you see as the main drivers for the decision to invest (or not) in this technology?					
What is the useful project life of this investment? (Useful economic life for valuation purposes) (years)					
What is your effective tax rate? (%)					

FURTHER COMMENTS

How do you see the anaerobic digestion market changing over the next 5 years?

How do you see the gate fee market evolving over the next 5 years?

How secure is your current feedstock supply? Do you foresee any problems with availability? How do you think feedstock usage across the market will change over the next 5 years?

How do you see hurdle rates evolving over the next 5 years?

How do project constraints or cost/financing implications vary across community-led/shared ownership projects and commercial projects?

Any other comments?

PARSONS BRINCKERHOFF

MICRO CHP

Name	
Company	
Email	
Telephone	
Company Type	

If required, Parsons Brinckerhoff will keep your responses anonymous.

Notes for completion of questionnaire
1. Please provide all costs as they were at the time they were incurred and do not adjust for inflation, but please state the year in which they were incurred. In other words, please express costs in real money terms of the year in which you incurred them. If you prefer to provide nominal costs (i.e. costs expressed in today's terms), please state the base year and which price index you are linking to (i.e. RPI, CPI, etc), either by adding a comment to the cell or by using the comment box at the bottom of this page.
2. Installation (CAPEX) costs should include the design, procurement and construction costs (e.g. EPC costs) and equipment and civil works costs. They should NOT include owner's costs, grid connection costs or substation and/or transformer costs.
3. Installation cost should be the cost at date commissioned.
4. Grid connection costs should include any upfront connection payment and substation/transformer costs but exclude pre-connection securities.
5. OPEX costs should include labour, planned maintenance and lifecycle replacement. They should NOT include land costs, property and business rates tax costs, rental and community benefit payments. Variable OPEX may also include water and/or chemical usage.
6. Export fraction is the average annual fraction of electricity generated by the project and exported to the grid.
7. The 'hurdle rate' is the minimum expected project Internal Rate of Return (IRR) for investment in a generation asset realised over the life of the asset, at which investors will make a decision to proceed with the investment. Our preference would be to obtain this on a real, pre-tax basis; however should you chose to provide it on a nominal and/or post-tax basis, please indicate so either by adding a comment to the cell or by using the comment box at the bottom of this page.
8. 'Gearing' is defined as the proportion of debt in the project's capital structure; in other words it is the percentage of total project costs that is funded by debt.
9. The 'effective' tax rate is the implied tax rate on a project after accounting for the debt interest tax shield (if relevant) and capital allowances.
10. Please add more columns or rows to tables as necessary.
11. If you wish to clarify any of your answers, please use the comments box at the bottom of this page.

TECHNICAL ANALYSIS

	Facility				
	1	2	3	4	5
Installed electrical capacity (kW)					
Date commissioned					
Installation cost (CAPEX) (£/kW)					
incl. VAT? (Y/N)					
Landownership type					
CAPEX costs pertaining to land (i.e. purchase cost/total land rental during construction) (£/kW)					
Grid connection costs (£)					
Grid connection type					
Where is the site located?					
Distance from project to grid connection (km)					
Fixed maintenance cost (OPEX) (£/kW/yr)					
Variable maintenance cost (OPEX) (£/kWh)					
If site is leased/rented, what are annual land costs? (£/kW)					
Connection Use of System charges (£/kW/yr)					
Engine manufacturer					
Load factor (%) - predicted					
Load factor (%) - actual					
Electrical efficiency (%)					
Export fraction (%)					
Have you signed a PPA agreement for the project?					
If yes, what rate do you sell to the grid at? (p/kWh)					
Fuel type					
Installed thermal capacity (kWth)					
Are you intending to use the heat generated?					
If so, have you, or are you indending to imply for the RHI?					
Are you intending to use the biogas for a purpose other than for electricity generation?					
If yes, do you intend to claim support under an alternative incentive scheme?					
Which scheme(s)?					

ECONOMIC ANALYSIS

	Facility				
	1	2	3	4	5
What is your hurdle rate for this investment? (%)					
What is the gearing of this project? (%)					
What is the cost of the debt? (%)					
What is your required return on equity? (%)					
What is the tenor of loan on this investment? (years)					
What risks do you see as the main drivers for the decision to invest (or not) in this technology?					
What is the useful project life of this investment? (Useful economic life for valuation purposes) (years)					
What is your effective tax rate? (%)					

FURTHER COMMENTS

How do you see the CHP market changing over the next 5 years?

How do you see hurdle rates evolving over the next 5 years?

How do project constraints or cost/financing implications vary across community-led/shared ownership projects and commercial projects?

Any other comments?

PARSONS BRINCKERHOFF

HYDRO

Name	
Company	
Email	
Telephone	
Company Type	

If required, Parsons Brinckerhoff will keep your responses anonymous.

Notes for completion of questionnaire

1. Please provide all costs as they were at the time they were incurred and do not adjust for inflation, but please state the year in which they were incurred. In other words, please express costs in real money terms of the year in which you incurred them. If you prefer to provide nominal costs (i.e. costs expressed in today's terms), please state the base year and which price index you are linking to (i.e. RPI, CPI, etc), either by adding a comment to the cell or by using the comment box at the bottom of this page.
2. Installation (CAPEX) costs should include the design, procurement and construction costs (e.g. EPC costs) and equipment and civil works costs. They should NOT include owner's costs, grid connection costs or substation and/or transformer costs.
3. Installation cost should be the cost at date commissioned.
4. Grid connection costs should include any upfront connection payment and substation/transformer costs but exclude pre-connection securities.
5. OPEX costs should include labour, planned maintenance and lifecycle replacement. They should NOT include land costs, property and business rates tax costs, rental and community benefit payments. Variable OPEX may also include water and/or chemical usage.
6. Export fraction is the average annual fraction of electricity generated by the project and exported to the grid.
7. The 'hurdle rate' is the minimum expected project Internal Rate of Return (IRR) for investment in a generation asset realised over the life of the asset, at which investors will make a decision to proceed with the investment. Our preference would be to obtain this on a real, pre-tax basis; however should you chose to provide it on a nominal and/or post-tax basis, please indicate so either by adding a comment to the cell or by using the comment box at the bottom of this page.
8. 'Gearing' is defined as the proportion of debt in the project's capital structure; in other words it is the percentage of total project costs that is funded by debt.
9. The 'effective' tax rate is the implied tax rate on a project after accounting for the debt interest tax shield (if relevant) and capital allowances.
10. Please add more columns or rows to tables as necessary.
11. If you wish to clarify any of your answers, please use the comments box at the bottom of this page.

TECHNICAL ANALYSIS

	Facility				
	1	2	3	4	5
Installed electrical capacity (kW)					
Date commissioned					
Installation cost (CAPEX) (£/kW)					
incl. VAT? (Y/N)					
Landownership type					
CAPEX costs pertaining to land (i.e. purchase cost/total land rental during construction) (£/kW)					
Grid connection costs (£)					
Grid connection type					
Where is the site located?					
Distance from project to grid connection (km)					
Fixed maintenance cost (OPEX) (£/yr)					
Fixed maintenance cost (OPEX) (£/kW/yr)					
Variable maintenance cost (OPEX) (£/kWh)					
If site is leased/rented, what are annual land costs? (£/kW)					
Connection Use of System charges (£/kW/yr)					
Load factor (%) - predicted					
Load factor (%) - actual					
Efficiency (%)					
Export fraction (%)					
Have you signed a PPA agreement for the project?					
If yes, what rate do you sell to the grid at? (p/kWh)					
Turbine type (please select)					

ECONOMIC ANALYSIS

	Facility				
	1	2	3	4	5
What is your hurdle rate for this investment? (%)					
What is the gearing of this project? (%)					
What is the cost of the debt? (%)					
What is your required return on equity? (%)					
What is the tenor of loan on this investment? (years)					
What risks do you see as the main drivers for the decision to invest (or not) in this technology?					
What is the useful project life of this investment? (Useful economic life for valuation purposes) (years)					
What is your effective tax rate? (%)					

FURTHER COMMENTS

How do you see the hydroelectric market changing over the next 5 years?

What is your opinion on site availability? Are suitable sites still available for development?

How do you see hurdle rates evolving over the next 5 years?

How do project constraints or cost/financing implications vary across community-led/shared ownership projects and commercial projects?

Any other comments?

PARSONS BRINCKERHOFF

SOLAR PV - DOMESTIC SCALE

Name	
Email	
Telephone	
Property Type	

If required, Parsons Brinckerhoff will keep your responses anonymous.

Notes for completion of questionnaire

1. Please provide all costs as they were at the time they were incurred and do not adjust for inflation.
2. For roof mounted solar, select 'new build' under Project Type where panels were installed during the building of the house. Select 'retrofit' where panels were installed on the house at a later date.
3. 'Building integrated PV' should be completed where photovoltaic materials have been used to replace conventional building materials in a structure (e.g. roof, skylights). This does NOT include roof mounted solar PV.
4. 'Standalone' should be selected where your solar panels are groundmounted (installed on land near your property and owned by you)
5. 'Payback time' is defined as the length of time that the project takes to pay for itself through savings on electricity/energy bills and income from the Feed-in Tariff (FIT).
6. A 'government bond' may also be known as a 'gilt-edge security'.

	Project	
	1	**2 *(if applicable)***
Project Type		
What is the capacity of the solar PV installation you have installed/are seeking to install? (kW)		
Date commissioned (if applicable)		
What FIT rate do you receive/expect to receive for this installation? (p/kWh)		
If unknown, what is the **total** sum you receive from the FIT annually? (£)		
How much of this is from the **export tariff**? (£)		
If you have an installation on your property, what is the amount you paid for it? (£) (*Please specify the year you incurred the costs*)		
If you are seeking to install an installation, what is the maximum amount you would be willing to pay for it? (£)		
inc. VAT? (Y/N)		
Where is your home/the site located?		
What is the maximum payback time you would be willing to accept for this installation? (years)		
What is/was your annual electricity bill prior to installation? (£)		
What do you now pay/expect to pay for your annual electricity bill following installation? (£)		
How much electricity does your installation generate annually/is it expected to generate annually? (kWh)		
If known, what percentage of the electricity you generate do you export/expect to export to the grid rather than use at home/on site? (%)		
What are the annual running costs of your installation? (£) (*if any*)		
If you received a reasonable cash sum, please rank the following in order of your investment preference:		
1. Renewable Energy Installation — **First Choice:**		
2. Savings Account (*permanent*) or long term deposit in bank (*5 years*) — **Second Choice:**		
3. Cash ISA (*2 years*) — **Third Choice:**		
4. Fixed term Government Bond (*5 years*) — **Fourth Choice:**		
5. Early mortgage repayments — **Fifth Choice:**		
(please select)		
How long ago did you last change electricity providers?		

FURTHER COMMENTS

When planning your solar PV installation, was it more important for you to do something that saved you money (through reduced energy bills/FIT), or that could benefit the environment? Why?

Any other comments?

PARSONS BRINCKERHOFF

URN: 15D/434