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Department of Energy and Climate Change

Review of Renewable Electricity Generation Cost and Technical Assumptions

Study Report

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Ove Arup & Partners Ltd
8 Fitzroy Street
London
W1T 4BJ
United Kingdom
www.arup.com

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		Name	Daniel Percy	Daniel Percy / Filippo Gaddo	Filippo Gaddo
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Contents

Appendices

Appendix I

LCOE Results Summary

Appendix J

Peer Review

Disclaimer

The views expressed in this report and those of the authors, not necessarily those of the Department of Energy and Climate Change (nor do they reflect Government policy).

Executive Summary

Arup was appointed by the Department of Energy and Climate Change (‘DECC’) in February 2015 to carry out a review of electricity generation cost and technical assumptions of renewable technologies in the UK (‘the Study’). Arup’s work provided an independent assessment and was based on data supplied via a stakeholder engagement process, as well as published and internal sources. The Study allowed new estimates of electricity generation cost and levelised cost of electricity (‘LCOE’) to be forecast out to 2030.

The findings from the Study will support DECC in its policy formation and inform strategic decisions on supporting renewable generation. A key requirement of DECC was that the Study drew a comparison between the last review of generation costs carried out by ‘Arup 2011’[1] and ‘DECC 2013’[2]. A comparison between the LCOEs produced in the DECC 2013 publication and the analysis presented by the Study can be found in each technology chapters 3 to 18.

A key objective for DECC was to improve its evidence base on the cost of renewables with an aim of improving value for money from the renewable technology support. The data collection and analysis process were split into two data collection phases, each covering different technologies such as: solar; biomass; offshore wind; waste; hydro; marine; and geothermal technologies.

Table E1: Renewable Electricity Technologies to be covered

Technology group	Data collection phase	Renewable sub-categories
Solar	Phase 1	• >5MW • 1MW- 5MW (building mounted) • 1MW- 5MW (ground mounted)
Biomass	Phase 1, Biomass CHP. All other technologies phase 2.	• Biomass CHP • Dedicated >100MW • Dedicated 5MW - 100MW

[1] Arup. October 2011, Review of Generation Costs and Deployment Potential of Renewable Technologies in the UK

[2] DECC, December 2013, Electricity Generation Costs 2013

Technology group	Data collection phase	Renewable sub-categories
		• Cofiring Conventional[3] • Biomass Conversion • Co-firing Standard CHP
Onshore wind	Phase 1	Onshore wind
Offshore	Phase 1	Offshore wind, Round 2 and 3
Waste	Phase 1, ACT. All other technologies phase 2.	ACT, standard ACT, advanced ACT, CHP[4]
		Energy from Waste ('EfW) EfW CHP
		Anaerobic Digestion ('AD'), >5MW AD, 1MW - 5MW AD CHP
		Landfill gas
		Sewage Gas

[3] Please note that the cofiring cost and technical performance information presented in the Study is based on previously unpublished data from Arup 2011 study. Arup has uprated the data to 2014 values. It should be noted Arup received no cofiring generation data from its stakeholder engagement.

[4] Estimated based on ACT Standard, plus additional CHP and equipment cost.

Technology group	Data collection phase	Renewable sub-categories
Hydro and marine	Phase 2	Hydro >5MW[5] Tidal
Geothermal	Phase 2	Geothermal Geothermal CHP

The data and analysis from the Study will be used to inform policy and a range of strategic decisions on renewable technologies such as the setting of strike prices for future capacity auctions.

The Study included a significant primary research and data gathering exercise. To generate a representative and robust dataset across the technologies Arup gathered data from the following sources:

- **Stakeholder survey:** in total over 300 industry stakeholders were contacted, across the technology groups with a standardised questionnaire. The questionnaires for Phase 1 and Phase 2 are provided in **Appendix A**.
- **Third party reports:** reports produced by external companies such as Bloomberg New Energy Finance ('BNEF'), World Energy Council ('WEC'), International Renewable Energy Agency ('IRENA'), International Energy Agency's ('IEA')[6] amongst others were used for benchmark cost and technical information. Please note that a full list of the third party reports used is presented in **Appendix H.**
- **Arup internal sources:** a review of internal research reports on renewables generation cost and technical performance.

The data captured was used to estimate a 'representative' set of costs and technical parameters for each renewable technology under review. Data was prepared for all of the technologies presented in table E1 and was subject to a rigorous internal and external review. The Study included a comprehensive desk study which took into account and built upon the considerable literature available within the public domain.

A stakeholder consultation was carried out with the various organisations contacted to confirm the findings from the data provided. Where appropriate,

[5] Please note that the >5MW hydro cost and technical performance information presented in the Study is based on previously unpublished data from the Arup 2011 study. Arup has uprated the data to 2015 values. It should be noted Arup received no hydro electricity generation data at the required scale from its stakeholder engagement.

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[6] World Energy Outlook, 2014

Arup clarified key assumptions with stakeholders. An extensive range of stakeholders across all areas of the renewable energy sector (manufacturer, developers, and operators) were consulted and asked to input to the study. The objective was to ascertain cost data but also obtain stakeholder's views on expected future change in cost and technical performance for each technology under review. The questionnaire also asked stakeholders to provide their views on the constraints surrounding the supply chain and what could drive future changes in cost. The following table provides a summary of the process Arup applied to reach its LCOE values.

Table E2: Renewable Electricity Technologies Data Analysis Process

Process step	
Literature review	• A review of industry literature to gather benchmark information from reputable sources on project cost and technical performance.
Stakeholder consultation	• A consultation with stakeholders to collect cost and technical performance data, a view on current and future cost, a view on cost drivers and other technical / operational project information relevant for LCOE analysis. LCOE modelling was carried out to allow an assessment of the cost of electricity generation over the technical life of an electricity generator, including all of the costs over its lifetime including: construction cost, operation and maintenance.
Validation and benchmarking	• Cost and technical assumptions provided by stakeholders were validated with internal experts and external benchmarks to adjust for bias. To establish a representative set of cost and technical parameters for each technology Arup has applied its judgement to the stakeholder data provided.
Cost analysis and data ranges	• Estimate low, medium and high project cost and LCOE ranges for different types of renewable technology and capacity bands. Data on pre-development, construction and operating cost was collected. Other key technical information was also collected from stakeholders including electrical efficiency, load factor and capacity.
Forecast	• A forecast of project cost was developed based on the views of stakeholders, external reports, internal data and assumptions around future renewable capacity deployment. The aim was to estimate how cost could potentially change relative to deployment and therefore impact on the future value of LCOE.

1.1 LCOE calculation

Following the data collection and processing stage new LCOE values were calculated. The main components of the levelised cost calculation are:

- The development cost of a project which includes achieving planning permission and compliance with regulatory requirements.
- The capital cost of bringing a plant to operation.
- On-going fixed and variable costs of operating a renewable generator and keeping it available for generation.
- Fuel costs or gate fees and related technical assumptions such as fuel efficiency.
- Heat revenues for CHP technologies.
- Availability: defined as the maximum potential time that a generation plant is available to produce electricity annually. The factor will vary depending on how the plant is operated and the amount of downtime required for maintenance. For example, the expected availability of a PV plant is 99%, allowing for maintenance downtime, parts replacement, panel washing and hours of sunlight..
- Load factor: defined as the ratio of average annual output to its total potential output if a plant was to operate at full capacity over its lifetime.
- Pre-development, construction, operational time periods and the phasing of this spend.

To assess how LCOE might change over time, Arup derived a learning rate forecast for construction cost and operating costs. By combining the learning rate with deployment assumptions. Arup was able to estimate the change in key components of the levelised cost – in particular capital costs – between 2015 and 2030. The forecast was informed and generated using stakeholder views and an internal assessment of potential technical change. Arup has therefore provided a low, medium and high LCOE ranges to capture future uncertainty and potential variance. Cost and technical estimates generated by the Study reflect different technology characteristics, locations and scales of plant.

It should be noted that all LCOE values produced in this report are based on both hurdle rates used in DECC’s Electricity Generation Cost Report 2013 and updated hurdle rates developed by DECC. Hurdle rates are required for the LCOE calculation and allow DECC to understand how the cost of financing affects overall LCOE. In parallel to this Study, DECC also reviewed new hurdle rate evidence for the same renewable technologies. New hurdle rates were provided to Arup by DECC for LCOE calculations.

Chapters 4 to 19 provide Arup’s view on the key factors affecting LCOE since the Arup 2011 study. A summary of the low, medium and high LCOE values for each technology under review is presented below on figures E1 to E3.

- The updated LCOE values for the technologies analysed during phase one of the Study (solar, biomass, onshore wind, offshore wind and ACT) indicated an average reduction in LCOE of 18%[7] for a project commissioning in 2020 when compared to the DECC 2013 study (rebased to 2014 prices). A number of the more mature technologies have exhibited cost efficiencies with increasing deployment and economies of scale.

- The updated LCOE values for the technologies in phase two of the study show less consistent changes, with some technologies more and some less expensive when compared to the DECC 2013 figures. Technologies in phase two which showed an increase in LCOE included Energy from Waste, Energy from Waste CHP, wave, sewage gas and geothermal CHP. All other phase 2 technologies indicated a fall in cost of 17% on average across such technologies[8].
- For some of the 'less established' phase 2 technologies (e.g. wave, tidal and geothermal CHP), as they are still under development, cost synergies are yet to be established and therefore the figures are subject to higher uncertainties.

Arup's current study has applied a cost forecast index based on learning rates to forecast future LCOE values for 2020, 2025 and 2030. However there will remain a need for regular updates of the LCOE study due to uncertainty around the precise trends and step changes in cost, especially for the less mature phase 2 technologies. As noted below, the peer review of this work also identified uncertainty around trends in costs compared to Arup forecasts for phase 1 technologies, including for solar and offshore wind.

Table E3 provides a summary of the DECC and Arup LCOE values for each technology under review. The LCOEs represent a plant commissioning in 2020 and use DECC's current discount rate assumptions.

To support the analysis Arup's work was peer reviewed by academics from Imperial College[9] and Paul Younger of Glasgow University. Arup sought an external view on cost as part of its validation process, providing important experience and knowledge of the renewable technologies. Importantly the review has indicated a wide range of opinions and views on the technologies. Therefore, taking into account the divergence in opinion and the pace of historic cost reduction (e.g. PV and offshore wind), there is potential for additional cost reductions beyond those identified by the Study.

For renewable technologies capital cost range is the main driver of LCOE variability. However, as multiple costs and technical assumptions vary across projects, there is considerable uncertainty over an actual supply curve. For example, from varying operating costs, hurdle rates, and load factors.

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[7] Arithmetic average change in LCOE for the following phase one generation technologies: Offshore R3 (-17.3%); Onshore Wind >5MW (-24.9%); PV>5MW (-34.5%); PV 1-5MW ground (-25.9%); PV 1-5MW building (-28.2%); Biomass CHP condensing (-17.1%); Biomass CHP CHP-mode (-17.0%); ACT Standard (-34.3%); ACT Advanced (-8.6%); and ACT CHP (+28.0%).

[8] Arithmetic average change in LCOE for the following phase two generation technologies: AD (-34%); AD CHP (-27.3%); dedicated biomass (-16.8%); biomass conversion (-22.7%); landfill gas (-16.9%); tidal stream (-0.1%); co-firing enhanced (-11.4%); hydro large store (-11.6%); hydro 5-16MW (-11.2%)

[9] Arup would like to thank Ajay Gambhir, Matthew Hannon and Jeremy Woods for supporting the project.

Table E3: Renewable Electricity LCOE Summary, Project Commission 2020, 2014 Real Prices £/MWh**

Technology	(1) Current DECC LCOE results, 2014 prices	(2) Arup 2015 LCOE results, current DECC hurdle rate, 2014 prices	(3) Arup 2015 LCOE results, new hurdle rate, 2014 prices	% change between (1) and (2)	% change between (2) and (3)
	Medium	Medium	Medium		
Offshore Round 3	136	112	106	-17%	-6%
Onshore wind >5MW, UK	85	64	63	-25%	-1%
PV >5MW	92	60	67	-35%	12%
PV 1 to 5MW, ground	92	68	76	-26%	12%
PV 1 to 5MW, building mounted	92	66	73	-28%	11%
Biomass CHP condensing	206	171	163	-17%	-4%
Biomass CHP CHP-mode	206	171	162	-17%	-5%
ACT Standard	130	86	98	-34%	14%
ACT Advanced	165	150	148	-9%	-1%
ACT CHP	141	180	211	28%	17%
Anaerobic Digestion**	160	105	99	-34%	-6%
Anaerobic Digestion CHP**	147	107	103	-27%	-3%
Dedicated Biomass	129	108	96	-17%	-11%
Biomass conversion	113	87	87	-23%	0%
Energy from Waste	31	83	45	165%	-45%
Energy from Waste CHP condensing	31	147	124	377%	-16%

Energy from Waste CHP CHP-mode	31	154	125	400%	-19%
Landfill Gas	72	60	67	-17%	11%
Sewage Gas	112	176	191	57%	8%
Wave Energy (2025)* **	283	333	320	18%	-4%
Tidal Stream (2025)* **	245	343	328	40%	-4%
Geothermal CHP	158	181	184	15%	2%
Co-firing Enhanced	117	103	103	-11%	0%
Hydro Large Store	78	69	84	-12%	22%
Hydro 5-16MW	95	84	97	-11%	15%

**LCOE values (£/MWh) are presented to nearest integer.*

*** AD LCOEs exclude digestate disposal costs.*

**** Tidal Stream and Wave Energy LCOE is for projects commissioning in 2025*

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Figure E1: Renewable Electricity LCOE Summary, Project Commission 2020, 2014 Real Prices £/MWh, DECC 2013 Hurdle Rates

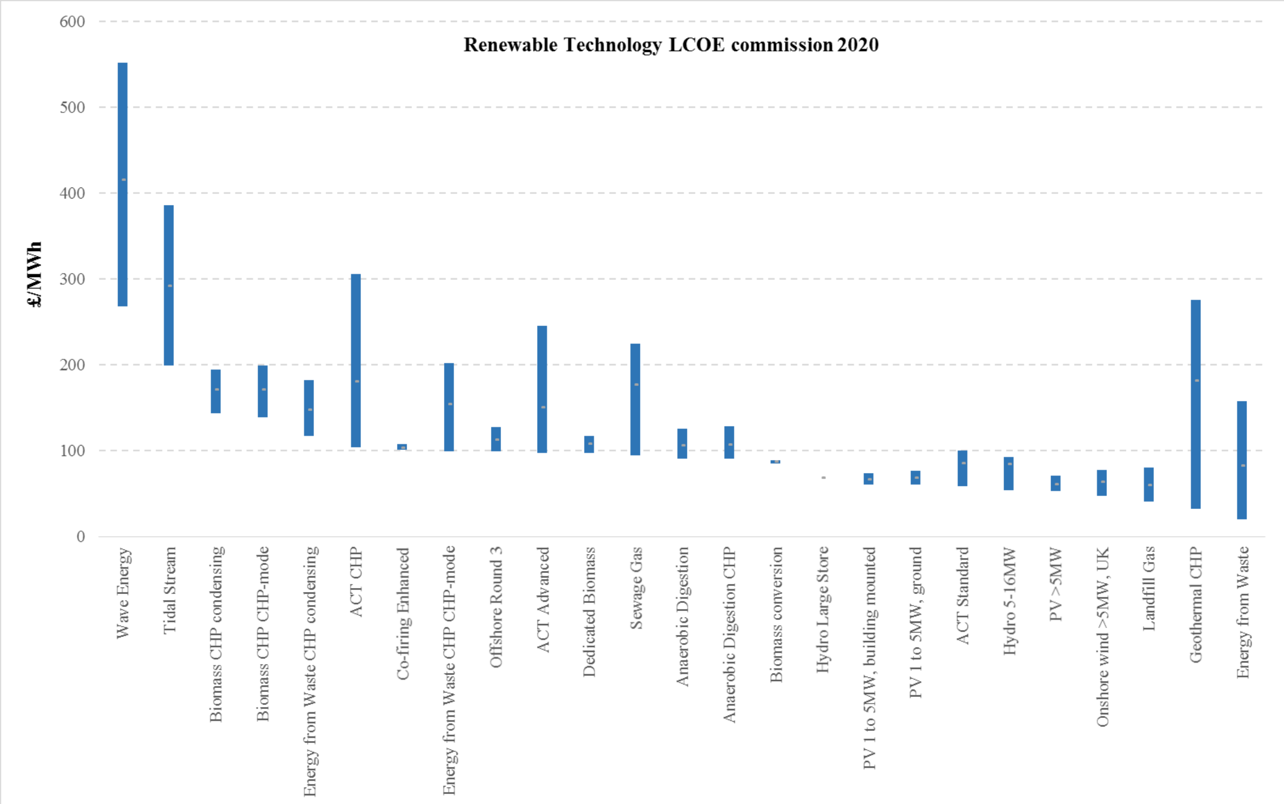
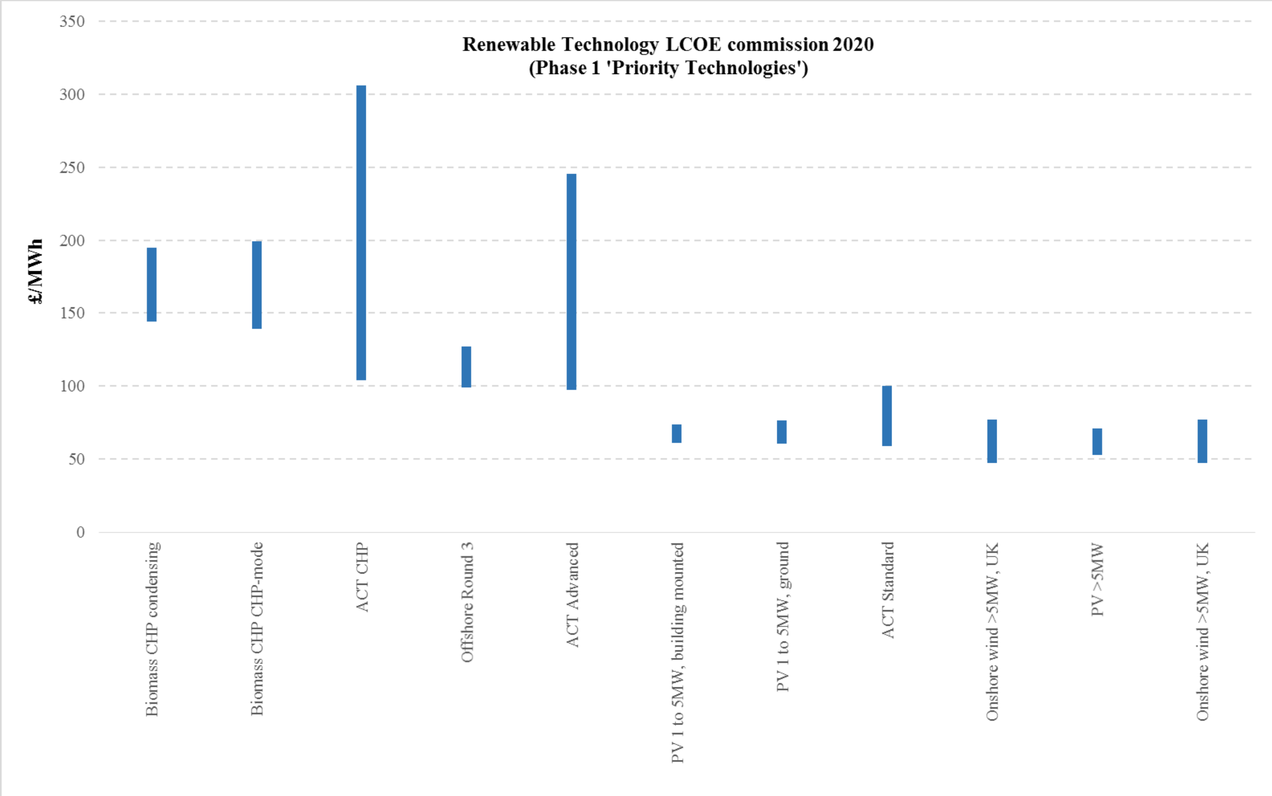


Figure E2: Phase One Priority Technologies Renewable Electricity LCOE Summary, Project Commission 2020, 2014 Real £/MWh, DECC 2013 Hurdle Rates



1.2 Phase 1 technologies

Technologies assessed in phase 1 of the work were: Onshore wind, Offshore wind, Solar PV, Biomass CHP and ACT standard. For these technologies changes in capital costs, large changes in operating costs and for wind technologies, significant increases in load factors, were the main contributor to changes in LCOE levels from the previous study. As noted above, all the LCOEs quoted below are for central assumptions at existing DECC hurdle rates in order to show the impact of the new Arup assumptions only, and do not reflect the expected LCOE after also taking account of updated hurdle rates. High and low points may have increased or decreased by different amounts.

Onshore wind: the data indicates that by 2020 will have an LCOE of around 25% less than current DECC figures. Key cost and technical drivers include falls in capital (-19% by 2020 compared to previous DECC figures) and operating cost (-31%) and a large increase in load factor (from 28% to 32%).

Offshore wind Round Three: the data indicates that a project commissioning by 2020 will have an LCOE 17% less than current DECC figures. Key cost and technical drivers include a small fall in capital cost (-11% but counterbalanced by an increase in pre-development costs), a larger fall in operating cost (-22%) and a large increase in net load factor (from 39.5% to 47.7%).

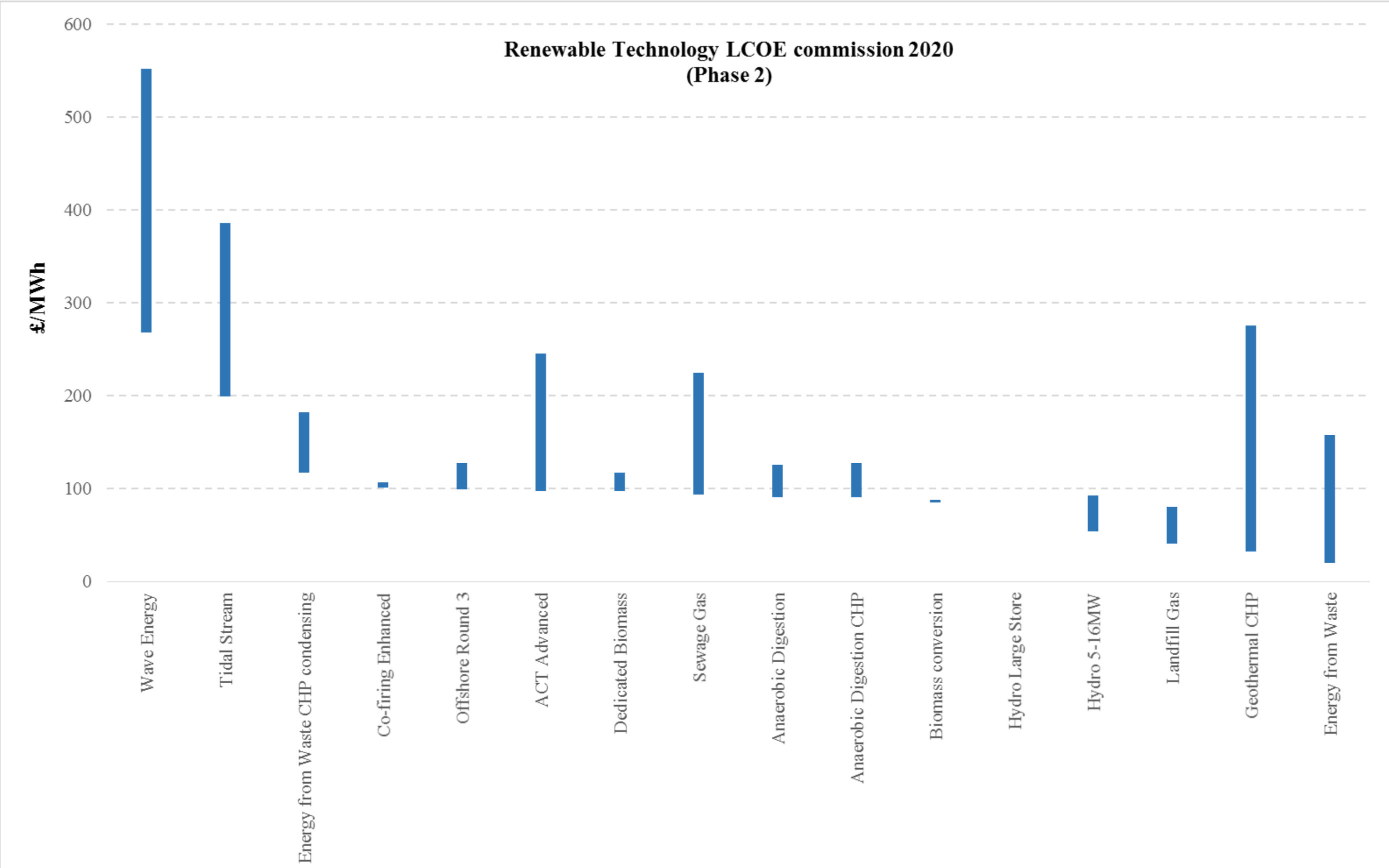
Solar PV: the data indicates that a project commissioning by 2020 will have an LCOE 26% to 35% less than current DECC figures. The key driver is expected to be further reductions in in capital cost -26% and operating costs 61% going forward.

ACT: for Advanced, Standard and CHP forms of ACT the data indicates that a project commissioning by 2020 will have an LCOE which is 9%, 34% less than current DECC figures. However, ACT CHP is expected to have an LCOE which is 28% higher than current DECC LCOE.

ACT advanced key cost and technical drivers include an increase in capital costs (3%), counterbalanced by a marginal decrease in operating cost (-2%). For ACT Standard, there is expected to be a small increase in construction cost (7%) and a large fall in operating costs (-30%).

Biomass CHP: the data indicates that a biomass CHP project commissioning by 2020, operating in condensing or CHP mode will have an LCOE 17% less than current DECC figures. Key cost and technical drivers include an increase in construction cost of 7% and 27% respectively cost, an increase in operating cost of 28% and 51%. These large increases in cost are outweighed by a large reduction in biomass CHP fuel prices.

Figure E3: Phase Two Renewable Electricity LCOE Summary, Project Commission 2020, 2014 Real Prices £/MWh, DECC 2013 Hurdle Rates



1.3 Phase 2 technologies

Biomass conversion: the data indicates that a project becoming operational by 2020 has an estimated LCOE of 23% less than current DECC estimates. The key drivers of this reduction can be attributed to a fall in capex (-36%) and operating costs (-23%), increases in load factor and generation efficiency.

Energy from Waste: for EfW and EfW CHP the data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE +100% higher than current DECC figures. Key cost drivers include a significant increase in construction cost (due mostly to a different and more representative dataset from the previous study) and a small reduction in load factor.

Dedicated biomass: the data indicates that a project commissioning by 2020 will have an LCOE -17% lower than current DECC figures, primarily due to a fall in capex costs (-20%), opex (-16%) and a decrease in fuel costs.

AD and AD CHP: the data indicates that a commissioning by 2020 is expected to have an LCOE which is 34% and 27% lower than current DECC figures. For AD the change in LCOE is a result of a fall in capex cost (-24%) and opex (-42%). For AD CHP there is an observed increase in capex of 9%, however this is counterbalanced by a fall in opex (-41%). In addition, for both forms of AD there has been an observed reduction in AD gate fees. It should also be noted that these LCOEs exclude digestate disposal costs, which is a core cost for this technology

Landfill Gas: data indicates that a project commissioning by 2020 will have an LCOE 17% less than current DECC figures. Key cost and technical drivers for landfill gas include an increase in capital cost (16%), and an increase in operating cost (17%) and a small increase in load factor.

Sewage gas: the data indicates that a project commissioning by 2020 will have an LCOE which is around 60% higher than the DECC 2013 figures. The main drivers are increases in both capex (53%) and operating costs (30%), despite a marginal increase in load factor.

Tidal: the data indicates that a project commissioning by 2025 will have an LCOE which is around 40% higher than the DECC 2013 figures. The main drivers are a significant increase in capex (70%) and smaller increase in operating costs (28%).

Wave: the data indicates that a project commissioning by 2025 will have an LCOE which is around 18% higher than the DECC 2013 figures. The main driver was an increase in operating costs (59%) and capex costs (14%). Load factor has also decreased marginally.

Geothermal CHP: the data indicates that a project commissioning by 2020 will have an LCOE which has decreased by 15% when compared to DECC’s current LCOE estimate. The main driver behind the observed change is a large increase in the expected construction cost (48%). The increase is however offset by improvements in expected heat revenue and a marginal fall in opex (-9%).

Co-firing: the stakeholder engagement process did not yield any new data for co-firing. In terms of cost and the technical requirements to deliver a co-firing project Arup has assessed the requirements to be broadly similar to biomass conversion.

Therefore, in the absence of data Arup has applied the change in conversion cost (2010 to 2015) to Arup's advanced co-firing dataset to generate new construction costs. New estimates indicated that a project becoming operational by 2020 (two years development and construction periods) has an estimated LCOE around £103/MWh. The drivers of this reduction are a large fall in capex cost (-39%). DECC has not published an estimate for this technology previously.

Hydro: the stakeholder engagement process did not yield any new data for >5MW hydro generation. Therefore, Arup has used the 2011 cost estimates and indexed to IHS's European Power Capital Cost Index ('EPPCI'). New estimates indicate that a hydro 5-16MW and a large store project becoming operational by 2020 will have an estimated LCOE which is 11% and 12% lower than DECC's current estimates. The drivers of this reduction are a large fall in capex cost of 17% and 18% respectively. In addition, a fall in operating costs of 1% is also expected.

2 Introduction

Arup was appointed by the Department of Energy and Climate Change ('DECC') in February 2015 to carry out a review of generation cost and technical assumptions of renewable technologies in the UK to 2030 ('the Study'). Arup's work provided an independent assessment based on data supplied via a stakeholder engagement process, as well as published and internal sources. Analysis from the Study allowed new estimates of generation cost and levelised cost of electricity ('LCOE') to be made for renewable electricity generation projects to 2030.

The findings from this study will ultimately be used by DECC to support policy and inform strategic decisions about renewable technology support. A key requirement of DECC's was that the review and assessment was compared to work including the last review of generation costs carried out by 'Arup 2011'[10] and 'DECC 2013'[11].

The data collection and analysis process was split into the following two data collection phases each covering different technologies such as: solar; biomass; offshore wind; waste; hydro; marine; and geothermal technologies.

Table 1: Renewable Electricity Technologies to be Covered[12]

Technology group	Data collection phase	Renewable sub-categories
Solar	Phase 1	• >5MW • 1MW- 5MW (building mounted) • 1MW- 5MW (ground mounted)

[10] Arup. October 2011, Review of Generation Costs and Deployment Potential of Renewable Technologies in the UK

[11] DECC. December 2013, Electricity Generation Costs 2013

[12] Arup also considered during the analysis additional technology sub-categories. For example, Offshore Wind Round Two, Offshore Wind </>30km from shore, Onshore Wind England, Onshore Wind Scotland etc, PV all categories. Please see Appendix I for a summary of the estimated LCOEs.

Technology group	Data collection phase	Renewable sub-categories
Biomass	Phase 1, Biomass CHP. All other technologies phase 2.	• Biomass CHP • Dedicated >100MW • Dedicated 5MW - 100MW • Cofiring Conventional[13] • Biomass Conversion • Co-firing Standard CHP
Onshore wind	Phase 1	Onshore wind
Offshore	Phase 1	Offshore wind, Round 2 and 3
Waste	Phase 1, ACT. All other technologies phase 2.	ACT, standard ACT, advanced ACT, CHP[14]
		Energy from Waste ('EfW) EfW CHP
		Anaerobic Digestion ('AD'), >5MW AD, 1MW - 5MW
		Landfill gas
		Sewage Gas
Hydro and marine	Phase 2	Hydro >5MW[15]

[13] Please note that the cofiring cost and technical performance information presented in the Study is based on previously unpublished data from Arup 2011 study. Arup has uprated the data to 2015 values. It should be noted Arup received no cofiring generation data from its stakeholder engagement.
[14] Estimated based on ACT Standard, plus additional CHP and equipment cost.
[15] Please note that the >5MW hydro cost and technical performance information presented in the Study is based on previously unpublished data from the Arup 2011 study. Arup has uprated

Technology group	Data collection phase	Renewable sub-categories
		Hydro large store Tidal
Geothermal	Phase 2	Geothermal Geothermal CHP

2.1 Context

DECC indicated that the findings from this study would be used to inform policy and a range of strategic decisions on renewable technology.

Arup's work was focussed on gathering generation cost and technical data for the renewable technologies listed in table 1 above, providing DECC with an updated view on the LCOE. In parallel DECC also reviewed hurdle rates for the same renewable technologies. New hurdle rates were provided to Arup for the LCOE calculation. Hurdle rates for each technology are required for the LCOE calculation and allow DECC to understand how the cost of financing effect overall LCOE estimates. For the Study, Arup (i) calculated the LCOE for each technology under review with results presented at the end of each technology section (please see Section 4 to 19) based on the hurdle rates currently assumed by DECC for modelling purposes; and (ii). **Appendix I** and the main report provides the LCOE values for each technology based on the above updated hurdle rate data. For the project the hurdle rate is defined as the minimum Internal Rate of Return ('IRR') at which investors would be willing to commit capital to a generation project.

Arup's work took into account and built upon a significant stakeholder engagement and literature review process. Arup gathered new data from a number of sources including renewable generation developers, utility companies and internal research.

2.2 The Project

The Study was concerned with assessing the cost and performance of developing new renewable generation capacity. The objective was to produce new and updated evidence on renewable life-cycle cost, enabling new LCOE estimates to be made. Arup's work covered a review of industry literature and the gathering of new project costs for each renewable technology, including information on capital

the data to 2015 values. It should be noted Arup received no hydro generation data at the required scale from its stakeholder engagement.

expenditure, operating expenditure, load and capacity factors. The analysis was also supplemented using internal benchmarks and experience.

The stakeholder engagement process was an important part of the analysis and assumed that stakeholders had provided their ‘best’ estimate of cost for new renewable projects. Although we have primarily relied upon the data provided by stakeholders, it has been tested against published benchmarks and internal knowledge to make it suitable for LCOE estimation and adjusted for bias, where necessary. To address gaps within the data Arup used benchmark values, providing a comprehensive view of cost and technical performance. A summary of the methodology used to analyse and generate a representative set of costs is provided in Chapter Two of this report.

To generate a representative and robust data set across the technologies Arup gathered data from the following sources:

- **Stakeholder survey:** in total over 300 industry stakeholders were contacted, across the technology groups with a standardised questionnaire. The questionnaire issued during both phases of work is provided in **Appendix A.**
- **Third party reports:** reports produced by external companies such as Bloomberg New Energy Finance (‘BNEF’), World Energy Council (‘WEC’), International Renewable Energy Agency (‘IRENA’), International Energy Agency (IEA) amongst others. Please note that a full list of the third party reports used is presented in **Appendix H.**
- **Internal:** a review of internal research reports on renewables generation cost and performance.

The final cost and technical inputs used to produce the LCOE figures reported here are primarily based upon evidence from the stakeholder survey but were benchmarked against external sources. The data captured was used to estimate a ‘representative’ set of costs and technical parameters for each renewable technology.

To assess how LCOE could change over time Arup derived a learning rate forecast for capital and operating costs. By applying the learning rate together with deployment assumptions Arup was able to estimate the change in life-cycle cost between 2015 and 2030. The forecast was informed and generated using stakeholder views and an internal assessment of potential technical change as a result of deployment and learning effects. By applying increasing and decreasing cost Arup was able to provide an assessment of future LCOE.

It should be noted that the LCOE values calculated by the Study are subject to a degree of uncertainty. Arup has therefore provided a low, medium and high LCOE range to capture future uncertainty and potential variance. The ranges effectively represent the highest and lowest capex cost unless otherwise stated.

Arup used third party data to validate the aggregated results produced via the stakeholder survey. This approach adopted was to test that the survey evidence received was of a similar order to the information published within the public domain.

As part of this study Arup considered a broad range of costs covering different stages of project development. The full dataset of costs reviewed may include projects whose costs sit outside the 'typical' cost range due to issues related to the specific project or may relate to respondent bias in completing a survey. Chapter Three provides an overview of the approach deployed to remove costs that were assessed to be 'non-typical' or not representative. The assessment process involved four stages including: visually identifying outlier project costs; removal of the 10/90 percentile projects (lowest to highest cost); internal technical review; and a correlation analysis against the key project variables to test the LCOE results for the various technologies. Arup also quantified and reviewed the costs for technology subcategories to observe if there was any observable differences between technology sub-categories.

To test the LCOE results and establish high and low scenarios Arup carried out a correlation analysis of the key costs drivers for selected technologies (onshore wind, offshore wind, biomass CHP and PV). The results of the analysis are presented in **Appendix G.**

It should be noted that the cost and technical estimates generated by the Study have been estimated to reflect different technology characteristics, locations and scales of plant. The final set of representative costs is presented in the technology chapters with alternative LCOEs provided in **Appendix I** (e.g. for offshore round 2, and distance from shore).

3 Methodology

This chapter provides a summary and overview of the Arup methodology used to develop a representative set of renewable data. The aim here is to provide an overview of the approach and logic used to arriving at the cost and technical estimates provided by the report. The main steps in the methodology were as follows:

- Apply a methodology that was consistent with previous studies, taking into account previous allocation of cost.
- Cross-examine and compare stakeholder data with external third party evidence on generation cost and performance for a new renewables project being developed in 2015.
- Establish project cost ranges (high, medium and low) for different groups of installed capacity for each renewable technology. This included current project cost for pre-development, capital and operational expenditure. Other key technical project data was also collected from stakeholders including efficiency and load factor.

3.1 Research Design

This section provides an overview of the method for collecting primary data via stakeholders that are active in the development of new renewable generation technology. The survey was split between Part A that focussed on collecting new data and Part B that focussed on collecting stakeholder views on future change in technology cost and performance. The aim was to collect enough reliable data so that a representative lifecycle cost for each technology could ultimately be produced.

Stakeholders were asked to provide data around the cost of bringing a project from pre-development i.e. the planning stage, to construction and operation, allowing Arup to form a view on the lifecycle cost and performance of each technology. While the data gathered by the survey is more detailed than previous, it should be noted that the levelised cost template used for modelling has not changed. Arup provided DECC with the same methodology as the Arup 2011 Study. As a result of the additional data collected by the Study, Arup has been able to analyse the contribution of specific cost components to LCOE. For example, the Arup 2011 survey requested a single UoS figure whereas for the Study UoS cost is broken down into TNUoS, BSUoS and DUoS. This has been beneficial in that it has allowed more detailed analysis and understanding of life-cycle costs.

To check for consistency in the responses Arup carried out an internal check of the stakeholder data. This involved checking that the values were entered correctly into the questionnaire and reviewing parameters against internal knowledge.

Part B of the questionnaire asked stakeholders to provide commentary (qualitative and quantitative) around expectations for future change in cost and what the key drivers are. For example cost drivers could include supply chain effects, commodity prices and labour.

3.2 Response Rate

The questionnaire was sent out during two phases. Overall, over **300** stakeholders were contacted and provided a reasonable balance between project developers, trade associations, equipment manufacturers and asset operators.

Overall Arup received 50 responses in total for both Phase One and Phase Two achieving a 17% response rate. Responses varied in terms of the quantity of information stakeholders were willing to provide, some opted to report only total cost with no disaggregation into individual cost components. In addition, some of the respondents provided only qualitative commentary on the expected direction of technology cost. In total, Arup received 47 with both quantitative and qualitative commentary and 3 responses which provided only commentary.

Every questionnaire provided the stakeholder with an option to provide data against the types of renewable generation it operates or develops. In some cases, to understand an individual stakeholder's cost, calls were made to clarify responses, understand values and views.

3.3 Criteria for Identification and Inclusion of Data

Prior to using the cost data for LCOE modelling an examination was carried out to determine:

- How reliable the data was.
- Whether cost falls within the expected range.
- Whether the questionnaire has been interpreted correctly.
- What is included within each element of cost.
- Whether there is consistency across datasets.
- Whether the data presented is in a consistent price base.

The questionnaire data has been reviewed against the criteria outlined above to ensure consistency of approach with previous analysis. The following points summarise our approach against criteria above:

- **Cost:** Arup's approach has been to check each questionnaire and ensure consistency across the dataset. This involved checking whether the data was in the same format, currency and cost base. Capital cost figures were expressed in £000/MW and operating costs in both £000/MW/a and £/MWh. All numbers presented in this report have been adjusted to 2014 prices where necessary. For the indexing the latest GDP deflator figures published by the Office for National Statistics (ONS) were used (consistent with the Arup 2011 study).
- **Stakeholder interpretation:** a review of the questionnaires indicated that most stakeholders provided data in the format required. However, in a few instances where values did not appear to be at the correct level, when compared to internal

benchmarks and external published values, clarification was sought on what was included. Arup has reviewed each questionnaire and established its overall usefulness to the Study in terms of providing accurate information for cost and LCOE modelling.

- **Data range:** For consistency with the Arup 2011 study the same data analysis methodology was applied to establish cost ranges. Arup’s initial step was to generate a scatter plot of the pre-development, capital and operating costs for the data points collected. Data plotting allowed for outlier projects, defined as significant variations from the mean or median cost to be visually identified.
- **Age and scale:** projects below a minimum size for the technology (please see table 1) and older than five years were excluded from the analysis. However, where data was poor alternative secondary sources of data were used along with cost data collected from some small-scale projects.

Figures 1 and 2 provides an example plot of data showing size of project (MW) versus the capital and operating costs. The review of the data allowed the high, low and mean/median range of operating and capital cost reported.

Figure 1: Example Stakeholder Data Scatter Graph – Outlier Identification

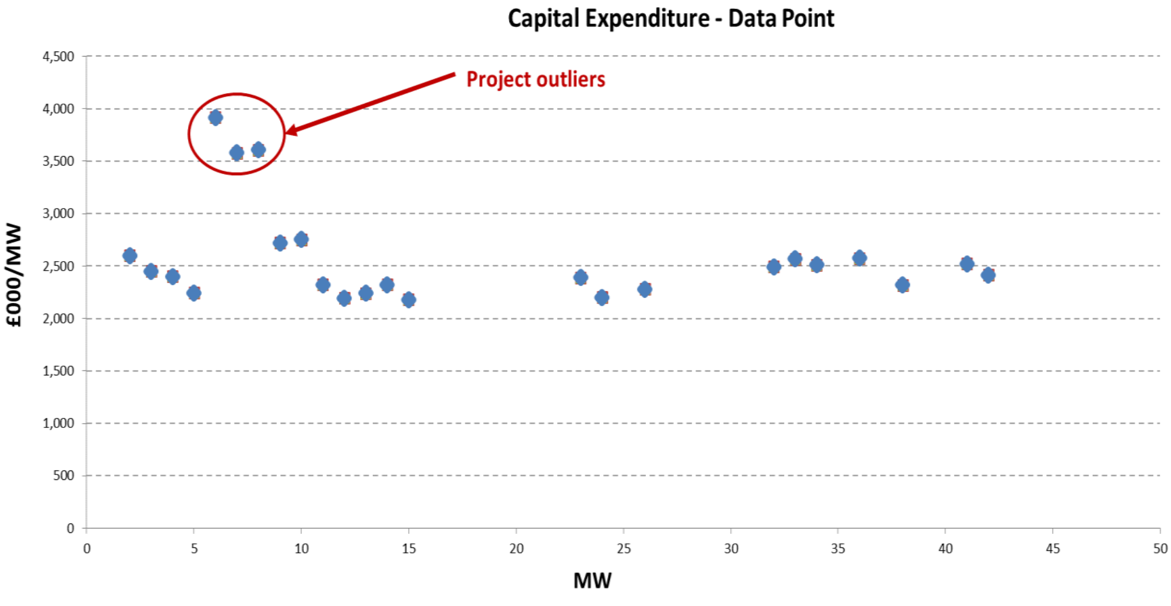
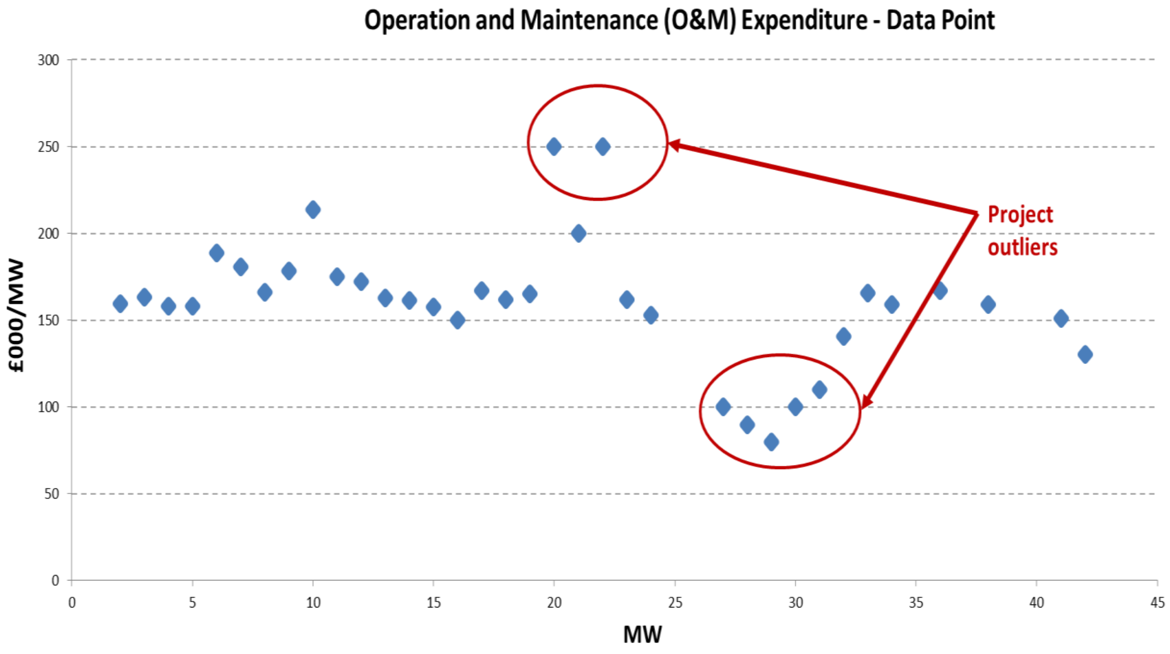


Figure 2: Example Stakeholder Data Scatter Graph – Outliers Identification



3.4 Outlier Identification

The aim of the outlier identification exercise was to establish a representative set of project costs. Following the same Arup 2011 methodology the initial step was to review the stakeholder data and identify which projects have capital and operating costs that sit outside of the expected range.

Following the same methodology applied for the Arup 2011 study high and low costs were calculated based on percentile ranks, 90 and 10. Cost was characterised as falling into one of three categories:

- Mean or median range (defined as between the 10th and 90th percentile).
- High cost (90th percentile).
- Low cost (10th percentile).

The application of the above rule was dependent upon the total number of data points available for the analysis. It should be noted that if there was less than 10 data points, the mean was calculated as a central value. In addition, where there were only three data points available, minimum, maximum and mean values were calculated. The rule applied to the data is presented in each renewable technology chapter.

The rule was applied for two reasons. The first was for consistency with the previous Arup 2011 study. The second was to provide greater accuracy around finding a ‘middle’ value. Median is a better measure when a large dataset is being measured (i.e. the middle point) and is less susceptible to being skewed by outliers, when a dataset is smaller, the mean can provide a stronger indicator. For example, if there are three value 1,5,20 the median is five. However, the mean value of nine a more central.

Applying percentiles to the data it allowed Arup to determine a reference range of cost which is consistent with the approach adopted for the Arup 2011 study. For LCOE it is standard practice to identify a range of cost data, rather than a single point, allowing for uncertainty and variance from the modelling to be captured

3.5 Cost Forecast

The cost of different technologies will change over time. To develop a capital and operating cost forecast for each technology Arup has taken into account the expectations of stakeholders, assumptions of technology specific learning rates and the deployment of technology at the global and UK level. External sources of data were also taken into consideration when the cost forecast was being prepared, a complete list is provided in **Appendix H.** External data were used for benchmarking and comparison purposes, providing assurance that the results are of the correct order. Where appropriate Arup has also used the cost and technical data to support the Arup analysis.

All of the cost estimates produced by Arup are for established Nth of a Kind (NOAK) projects. The exception to this rule is ACT advanced (ACT CHP), geothermal CHP, wave and tidal stream technology since there are only being a small number of projects in the UK.

Arup's approach to developing a cost forecast was consistently applied between Phases One and Two with the analysis based on a combination of the following:

- A literature review of expected learning rates and cost forecast.
- Data gathered via the stakeholder interview process.

Using both sets of data Arup was able to produce a future cost adjustment index for both capital and operating cost which was used to estimate future values of LCOE. The next two sections provide the approach Arup adopted for its literature review and development of its cost forecast.

3.5.1 Literature Review

For the forecast Arup's initial step was to develop a top-down forecast based on international learning rates produced from reputable sources. This included data from the International Energy Association ('IEA'); IRENA; BNEF; and trade organisations for each technology. Arup also reviewed the existing research material on historical cost trends for each technology. A complete list of the reports used to inform the analysis is presented in **Appendix H**.

Arup also reviewed global deployment forecast to understand the potential for future renewable capacity expansion. The main source of deployment data was produced by the IEA in World Energy Outlook (2014). It has formed a key input linking deployment to changes in key technology component costs bought and sold on international markets. For example, panels for PV and turbines for onshore / offshore wind.

3.5.2 Cost Forecast Model

Following the literature review, Arup's approach included the development of a model and analysis of cost which covered the following:

- Breaking down capital and operating costs into separate components. The objective here was to determine the key drivers of cost behind each.
- Based on research generated during the literature review (to determine cost drivers behind each component) Arup generated a Component Cost Index ('CCI') forecast, applying it to the components out to 2030.
- Linking cost components to deployment rates – either UK or Global deployment as appropriate. Arup used its research (and where relevant its proprietary UK power model) at either the global, EU or UK level to form its cost forecast[16]. Please see **Appendix C** for a summary of the cost reduction index applied to each technology cost. A summary of the how the learning rate and cost reduction forecast was prepared is provided in **Appendix E**.
- The CCI was then applied as an adjustment factor to the cost component generating a weighted learning rate index out to 2030. Please note that the base year was assumed to be year 2015.
- The final step was then to aggregate cost for the various components to obtain a future 2020 and 2030 capex and opex forecast that could be used for LCOE modelling purposes.

Stakeholders also provided views on the expected learning rates providing an industry perspective. As part of the stakeholder engagement process Arup asked stakeholders to provide information regarding their expectations for capex and opex cost to 2020 and 2030 respectively. To include stakeholder views Arup's approach was to carry out the following:

- Arup summarised the view from stakeholders' to produce a 2020 and 2030 costs forecast. The data sets were then used as part of the CCI index.
- The final step in the analysis was to integrate the results of the stakeholder and literature review processes, generating a combined CCI forecast to 2030.The final cost indexes produced for the Phase One and Two technologies are provided in **Appendix C.**

3.6 Limitations of the Cost Analysis

Arup has applied reasonable endeavours to check and verify the data provided via the stakeholders. It should however be noted that we have not carried out a detailed audit of the underlying cost items which constitute development, construction and operating cost.

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[16] Appendix E provides a summary of the learning rates Arup has assumed for its LCOE analysis. Appendix C provides a summary of the cost indexes used.

The impact and change in cost drivers on capital and operating costs were derived using information collected through the stakeholder consultation and internal data. Our approach to reviewing and incorporating stakeholder and third party published data is provided in Section 3.3. A comprehensive 'first principles' analysis of cost has not been undertaken. The stakeholder consultation, and the subsequent analysis, was limited in its overall scope and time, with a view to developing a representative set of cost ranges which could be used to inform LCOE modelling. To check consistency and potential bias of the final LCOE results, cost and technical inputs Arup carried out a benchmarking exercise based on internal data, UK and international publications.

Compared to the previous data collection exercise carried out for the Arup 2011 study the questionnaire is much more detailed[17] in terms of the data it has attempted to collect. For example, during the Arup 2011 study a single figure for UoS cost was requested; for this Study a detailed breakdown was requested to understand average UoS and the components which make it up including Transmission Network Use of System ('TNUoS'), Balancing System Use of System ('BSUoS') and Distribution Network Use of System ('DNUoS'). It should be noted that limited information was received in relation to providing a full breakdown of cost with a few stakeholders choosing only to supply total cost data with a limited breakdown.

Arup has also collected new data on developer fuel costs and gate fees. For consistency with previous work fuel costs (and to ensure transparency) these are excluded from the operating expenditure. A range of fuel costs have also been provided to DECC. This range has not been taken into account for the final LCOE calculations and ranges. There is an explanation of how the cost was derived presented in each technology chapter.

The capital and operating cost ranges generated by Arup can be explained by a variety of issues including scale effects, a trade-off between capital and operating cost, technological variations, requirements for fuel processing, different plant efficiencies, site specific conditions and how stakeholders account and allocate cost amongst the questionnaire categories . The totality of these factors, captured through costs and technical parameters ultimately drives the LCOE values. As a stand-alone set of figures the cost ranges produced for each technology take into account a wide variance in stakeholder views and differences in reporting cost. The analysis provided by the Study is consistent with previous work and has in our opinion produced a representative set of cost and technical parameters.

It should be noted that the data gathered on all biomass fuel types and the forecast generated did not take into account future availability of supply.

3.7 Load Factor Methodology

The approach adopted for estimating load factor included an initial review of publications and reports published in the UK and globally along with results from stakeholders, providing a combined view of how load factor might change in the future. The following provides a summary of the review which took place. A

[17] Appendix A provides the questionnaire issued to stakeholders.

summary of the load factors (gross and net) used for LCOE modelling are provided in the technical assumptions section of each technology chapter. A summary of the change in gross load factors over time are presented in **Appendix B**.

3.7.1 Literature Review:

The literature review examined publications that provided guidance on market trends and how changes in technology and efficiency will change load factors in the future. Examples include recent work carried out by the Crown Estate on offshore wind and Renewable UK's work around onshore wind, wave and tidal. A list of the reports used for the analysis are provided in **Appendix H.**

The literature review also examined how changes in deployment could spur technological change and the impact it would have on load factor. For example, Arup reviewed potential PV deployment and the different technologies it could facilitate along with the potential impact on load factor.

Arup also reviewed European and Global markets to understand what technical innovations in other countries could be delivered in the UK. Arup reviewed data and publications from reputable sources such as the IEA, IRENA and BNEF. By reviewing international data it provided additional perspective on potential UK market trends. Technical journal articles were also reviewed to provide an additional level of validation for our assumptions.

At the same time as Arup's work, Parsons Brinckerhoff ('PB') has also carried out a review of small-scale renewables. Arup used the costs generated by PB's analysis for comparison with the costs generated here. The technologies where a comparison could be made included PV and AD.

3.7.2 Stakeholder Responses:

Arup reviewed the stakeholder response to understand their view on future load factors. Where there was enough data Arup prepared a timeline of stakeholder projects, the expected operational start date and the expected load factor. The timelines were then used as part of the load factor and validated against results from the literature review.

Where possible, Arup used stakeholder responses as the basis for the load factor forecast comparing it to information obtained from the literature review. Following the comparison Arup integrated the results based on the assessed robustness of the information obtained via the stakeholder and literature review.

It should be noted that for certain mature technologies (especially thermal based) load factors are determined more by marginal cost and feedstock prices. In this situation, a long term forecast based on deployment and technological innovation was not applicable.

3.8 Technology Groups

Following agreement with DECC Arup has collected data on each technology and developed cost for each category listed in Table 1 above.

Conventions which have adopted for reporting include:

- Megawatt ('MW') in this report refers generally to electrical installed capacity and fully condensing capacity for CHP technologies (except when operating in CHP mode).
- Where megawatt thermal ('MWth') is reported it represents megawatts of thermal installed generation capacity. Please note that all MW / MWth values in this of report are **net figures**. i.e. we generally refer to plant output on a net basis after any internal plant losses are accounted for

3.9 Levelised Cost

The levelised cost of electricity generation is a metric used to analyse the marginal cost of electricity generation by different technologies. It can be defined as the ratio of net present value ('NPV') of total cost to the NPV of electricity generated over the operational life of a plant. It is typically reported as cost per MWh of electricity generated ('£/MWh').

Levelised cost is a useful metric for comparing different types of generation. It essentially represents the break-even tariff per MWh hour in present value terms required by a stakeholder to recover cost. The calculation therefore averages the cost of production over the life of a plant and allows both cost and generation to be converted into a single price. For the analysis there are two important aspects of the definition which need to be considered:

- What assets are included within the cost
- The operational time period over which the levelised costing will take place.

It should be noted that the definition of levelised cost applied in this report only takes into account the costs borne by developers in relation to construction and operation of a renewable generation project. It does not take into account the impact on the wider electricity network, revenue and support mechanisms such as CfD, RO and capital grants.

Project timing is an important dimension for the development, delivery and operation of a project. The following were factored into the calculation:

- The estimated time it takes for a project to go through design, construction and delivery.
- The expected operational life of the technology in question.
- The discount rate which allows the valuation of future values to be brought back to present values i.e. the value today of a future stream of costs.

Following the 2011 methodology Arup produced high, median/mean and low estimates for input into an LCOE model ('the Model'). LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital and operating cost. Therefore, it is the standard approach to consider a range of costs rather than a single point, allowing the modelling to capture uncertainty and variance.

Please note that a review of load factors has been carried out for each technology under review. A summary of the analysis is presented in each technology section.

3.10 Components of LCOE

This section outlines the main components of levelised cost and provides an approach which is consistent with the approach previously adopted by DECC. The calculation comprises the following items:

- The development cost of a project which includes achieving planning permission and compliance with regulatory requirements.
- The capital cost of bringing a generator to operation, including any associated infrastructure costs for grid connection.
- On-going fixed and variable costs of operating a renewable generator and keeping it available for generation. These also may include fuel costs and gate fees.
- Availability: defined as the maximum potential time that a generation plant is available to produce electricity annually. The factor will vary depending on how the plant is operated and the amount of downtime required for maintenance. For example, the expected availability of a PV plant is 99%, allowing for maintenance downtime, parts replacement, panel washing and hours of sunlight.
- Load factor: defined as the ratio of average annual output to its total potential output if a plant was to operate at full capacity over its lifetime.
- Pre-development, construction and operational time periods, along with how these costs are distributed across these periods.
- Fuel efficiency
- Heat revenues for CHP technologies are subtracted from the LCOE calculation.

3.10.1 Pre-development Costs

Pre-development costs include:

- Pre-licencing cost, technical and design was assumed to include costs associated with licensing, technical design, development and design selection
- Regulatory and public enquiry cost was assumed to include, public enquiry and local community engagement costs.
- Due to uncertainty around how future planning, public enquiry and regulatory requirements will change Arup assumed that pre-development costs would remain constant into the future for LCOE modelling purposes.

- Base pre-development costs reflect the costs for a project reaching final investment decision in 2015.

3.10.2 Capital Costs

Based on the stakeholder questionnaire capital costs for LCOE modelling were assumed to include the following:

- Total capital cost is assumed to include project design, procurement and EPC construction cost. In addition, other capital costs such as site works, roads and utility connections (water, gas etc.) were captured here. Other generation equipment such as CHP, boiler and other equipment were also captured.
- It should be noted that capital cost excludes interest costs during construction and the cost of land. In addition, it should be noted that the Arup cost forecast does not include a construction materials index e.g. steel prices. Please see Section 3.5.2 for detail on how Arup's CCI index was generated.
- Infrastructure cost was assumed to comprise of grid connection costs (e.g. underground cable costs), local substation and transformer stations and is a separate line item within the LCOE model. It should be noted that infrastructure cost is assumed constant going forward since it the focus of the on technology cost. The boundary of infrastructure is assumed to include the site where the generator is located, associated electrical infrastructure and connection to the nearest point on the grid.

  For offshore wind there is a different arrangement for the capture and allocation of transmission cost. Offshore transmission ('OFTO') construction costs for the electricity transmission cable are assumed to be excluded from the analysis. OFTO payments are assumed to be made by the wind farm owner and paid to the owner of the transmission cable and captured via operating costs.

  Base capital costs reflect the costs for a project reaching final investment decision in 2015.

3.10.3 Operating Costs

Operating costs include:

- Fixed O&M costs such as labour, planned and unplanned maintenance, spares and consumables.
- Variable O&M is calculated per MWh of generation. These are output related O&M expenditure, disposal and treatment of waste.
- The cost of insuring generation plant
- Network Use of System (UoS) charges. These are the costs of connecting to and using the transmission network. The UoS cost reported in Arup's analysis includes TNUoS and DUoS costs only calculated as a £/kW/per annum. BSUoS cost is charged to a generator on a £/MWh basis. For the analysis Arup has therefore included the BSUoS cost element with the

variable operating cost. It should be noted that the analysis does not take into account or estimate system wide costs.

- Base operating costs reflect the costs for a project reaching final investment decision in 2015.
- Fuel costs and gate fees for relevant technologies.

3.10.4 Use of System Cost

Stakeholders were asked to provide data on UoS charges. After an internal and external review of the data it was concluded that both TNUoS and DUoS charges were representative for the technologies under review. For BSUoS Arup used a benchmark cost provided by LeighFisher which represents an average balancing cost for UK generation. For consistency both Arup and LeighFisher included BSUoS with variable operating cost, and given this cost is also charges on a MWh basis.

3.11 Full Condensing and CHP-mode Operation

For the Study it was important to produce a set of costs for both CHP operating in full condensing and CHP-mode. It was assumed that when a CHP plant is producing electricity but not useful heat it operates in condensing mode, alternatively when it is producing useful heat and supplying it to a heat load it is operating in CHP-mode.

To support the analysis and understand the impact on electrical efficiency of either mode Arup engaged with Ricardo-AEA who provided LHV efficiency data for the technologies under review. It should be noted that for AD CHP and ACT CHP it was concluded that there is no impact on electrical efficiency of switching between modes. It should be noted that future geothermal CHP projects will be operated in CHP-mode and designed to produce both electricity and useful heat to supply nearby heat loads.

For biomass CHP and EfW CHP it was assumed that both technologies operate a condensing steam turbine to generate electricity. Here steam leaves the turbine at a low pressure to maximise power generation before being condensed and returned to a boiler. When the plants are operated in CHP-mode steam is typically diverted via outlets allowing steam to be diverted to serve heat loads. The impact is that the volume of steam going to the downstream stage and therefore the power generation is reduced, when compared to condensing mode operation where no steam will be extracted. To measure the impact on LCOE of operating biomass and EfW CHP in CHP-mode a cost adjustment was included. Based on data from Combined Heat and Power Quality Assurance (‘CHPQA’), Ricardo-AEA provided anonymised, representative set of low, medium and high condensing and CHP-mode LHV efficiencies. To estimate the impact on cost Arup assumed that the ratio of full condensing to CHP-mode LHV efficiency would provide a good approximation. For example if a CHP’s condensing efficiency is 27% and its CHP-mode efficiency is 23%, then the ratio applied to cost is 117%. i.e. a 17% uplift in cost for operating in CHP-mode (i.e.£/kW costs are higher to compensate for the reduced electrical output of the plant in CHP mode). The approach outlined above was discussed and agreed with DECC and has been used to estimate CHP-mode cost.

In addition it is assumed that CHP technologies receive heat revenues (£/MWh) which are included so that the estimates reflect the cost of electricity generation only. Heat revenue is estimated on a discounted present value basis and net off the final LCOE value calculated.

3.12 LCOE Range High and Low Scenarios

DECC has developed an Excel based LCOE model for the purposes of calculating levelised cost. The model was provided to Arup for the Study.

The model is flexible and allows sensitivity scenarios to be undertaken against the key cost and technical assumptions outlined above. The model outputs low, medium and high LCOE ranges based on the data inputs which were developed by Arup. The objective of Arup's work was to generate a high, medium and low range of LCOEs which take into account deployment and improvements in technical performance of renewables.

Arup has produced high and low LCOE ranges based on the cost and technical data collected. The ranges were generated by holding the "medium" or average value for each cost and technical variable (outlined above) constant with the exception of pre-development and construction costs; these were flexed between the low, medium and high, allowing an LCOE cost range to be generated. The LCOE estimates for each technology is provided at the end of each technology chapter along with a comparison of LCOE based on current DECC assumptions.

To allow a consistent comparison between Arup's 2015 and DECC's current levelised cost assumptions[18] both current and historic cost are reported in 2014 prices. A 'GDP Deflator' index from the Office for National Statistics ('ONS') has been used for the indexation process[19]. All costs comparisons provided in the technology sections are therefore consistent.

To estimate future values of LCOE Arup used a deployment forecast for each technology based on a range of sources, presented in each technology chapter . Deployment has been taken into account in the Arup model to generate learning rates. The methodology used to generate the cost forecast is presented in **Appendix E**.

It should be noted that for the analysis DECC's current hurdle rates were assumed, allowing the impact of a change in cost and technical assumptions on LCOE to be identified.

3.13 Correlation Analysis

Arup carried out a review of correlations between cost and technical variables. The objective here was to identify if there was a significant correlation between variables and understand the impact on the high and low estimates of LCOE. The

[18] Please note that the source of the cost assumptions is, DEC7C, Electricity Generation Costs, December 2013

[19] GDP Deflator – ONS, YBGB series.

analysis is presented in **Appendix G** of the report, providing an overview of the sensitivity analysis and new LCOE ranges.

The correlation analysis was applied only to offshore wind, onshore wind, PV and biomass CHP. After an internal and external review of the data it was concluded that for all other for all other technologies the data was of the correct order and representative. No additional correlation analysis was undertaken for the Phase 2 technologies.

4 Onshore Wind

4.1 Introduction

Since 2010 onshore wind in the UK has experienced a large rate of deployment relative to other forms of renewable generation. There is an expanding global market for onshore wind technology and is recognised as an important contributor toward the UK's renewables generation energy mix. Between 2012 and 2013 onshore capacity grew from 5,899MW to 7,513MW with a number of large-scale wind farms being delivered, including the 144 MW Fallago Rig. From a capacity perspective, by the end of 2013 onshore wind accounted for 38% of total renewable generation capacity[20].

The Arup 2011 report estimated generation cost and technical performance for only two size categories <5MW and >5MW. To provide an increased level of detail and observe if there are geographical differences in cost and technical performance, Arup initially split its dataset into four sub-regions (England, Scotland, Wales and Northern Ireland). Following a review of the LCOEs produced for each region Arup observed that no statistically different results between the UK and country levels. For the analysis Arup has therefore reported the results at the UK level only. A breakdown of LCOE at the country level is provided in **Appendix I.** The final category reported in this chapter is:

- All of UK (no regional disaggregation)

It should be noted that the estimates produced for onshore wind are for projects which could be CfD supported and assumed to be >5MW. Projects which are <5MW are assumed to be supported by FiT and were not considered as part of the analysis. Arup therefore focussed on collecting data for onshore wind projects at the >5MW scale.

4.2 Data Collection

Data sets were collected from a broad mixture of public, internal and stakeholder sources. For the data collection process Arup contacted manufacturers, projects developers and utility companies. Overall, data sets were collected from a mix of sources and 8 project developers, yielding around 60 project data points.

Based on the data collection criteria outlined in Chapter 3, 42 data points were assessed to be robust, representative and useful to the analysis. At a regional level the projects were evenly dispersed with broadly 13 projects located in England, Scotland and Wales. For Northern Ireland the overall data set was quite small with only 4 data points collected. In addition to stakeholder responses Arup also benchmarked and compared the stakeholder data against industry market data.

In terms of installed capacity the 60 data points collected represented 1,698MW of projects at various stages of development (operational, under construction and planned). Post evaluation, the final 42 data points used for the analysis had an

[20] DECC, 2014. Digest of United Kingdom Energy Statistics 2014

estimated capacity of 1,276MW. Based on the available data average plant size ranges from a low of 9MW to a high of 50MW, the medium installed capacity was calculated to be 20MW.

From the data received stakeholders typically assumed a technical operational life of between 20 and 25 years.

4.2.1 Capital Expenditure

Turbine and construction costs are the most significant element of cost with the average ('medium') equal to around £1.25m/MW. Other costs such as grid connection contribute an additional £0.16m/MW. Pre-development cost which include achieving planning permission, regulatory compliance and design are around £0.1m/MW. Combining the pre-development, construction and infrastructure costs totals £1.53m/MW. The data collection was for sites between 9MW and 50MW of installed capacity.

Pre-development costs include public enquiries, licensing, radar mitigation, design consultancy and habitat enhancement measures. As expected costs will vary on a project-by-project basis as variation is frequently driven by difficulty in obtaining planning consent and dealing with appeals. The following tables presented the capital cost of developing a UK wind farm project.

Table 2 Onshore Wind (UK) Total Capital Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000/MW	UK
Low	1,032
Medium	1,527
High	1,943

Table 3 Onshore Wind (UK) Total Capital Cost Breakdown for a Medium Project %

Capital cost item	UK
Pre-development	7.2%
Construction	82.0%
Infrastructure	10.8%

4.2.2 Capital Cost Learning Rate Assumption and Forecast

Stakeholders were asked to provide a view on what they considered to be the main cost drivers behind pre-development, construction and operations cost. Based on stakeholder feedback and publically available literature an Arup view on the future direction of cost was prepared and developed into a learning rate forecast.

Arup's approach initially involved developing a forecast split by component with turbine costs taking into account different learning rates and linked to global deployment of onshore wind. Other cost components for capex were also linked to UK deployment. **Appendix E**, provides a summary of the learning rate forecast for onshore wind. Based on an analysis of learning rates and deployment the reduction in cost is expected to be 5% by 2020, 8% by 2025 and 11% by 2030, which is equal to an annual reduction of -1%. The learning rates has been estimated based on data from stakeholders and the IEA. To obtain our rate 16.9GW of onshore wind is expected to be deployed by 2030.

From a construction cost perspective the main drivers were reported to be exchange rates, availability of finance, transportation, labour and commodity prices (steel and copper). Over the long-run however stakeholders expect construction cost to continue to fall driven primarily by reductions in turbine cost and improvements in the efficiency of project delivery.

Stakeholders also reported their expectations for pre-development cost to be either flat or increasing over the long-run. Future cost drivers that have been cited include: onerous planning conditions; appeals; availability of good sites with viable grid connection points; and increasingly stringent EIA reporting.

Arup's learning rate forecast has been applied to only construction cost. For modelling purposes and consistency with previous work, pre-development and infrastructure cost were assumed to be constant.

Table 4 Onshore Wind (UK) Capital Cost Forecast 2015 – 2030 (UK), 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	1,032	987	959	939
Medium	1,527	1,464	1,423	1,395
High	1,943	1,865	1,814	1,780

4.3 Operating Cost

Operating costs for wind comprise of fixed and variable O&M contracts, UoS charges, insurance and labour. Table 5 illustrates the variation in cost at the UK level. Operating cost is understood to vary depending on regions and are driven by local conditions such as availability of labour, local grid charges, price and availability of components.

Table 5 below provides an indication of the variation in operating cost. Overall, for the UK the cost ranges from £41k/MW to £93k/MW. At the regional level cost is expected to be mainly driven by specific local market conditions, including availability of suppliers. In addition, UoS cost are known to vary depending on the region where a project is deployed.

Table 5 Onshore Wind (UK) Operating Costs (Financial Close 2015), 2014 Real Prices £’000/MW

£’000s/MW	UK
Low	41
Medium	42
High	93

4.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs stakeholders identified labour and availability of components as an important cost driver. Stakeholders indicated that they expect operating costs to remain flat with some potential for reduction.

For the opex learning rate forecast Arup combined information from stakeholders along with data from a literature review. Four categories of opex were considered which included fixed and variable O&M, insurance and grid costs. For grid costs Arup used its own UoS assumptions, insurance was linked to capex, fixed and variable opex were linked to the views reported by stakeholders.

Appendix C, provides a cumulative summary of the cost index forecast applied to onshore wind generation. Based on an analysis of learning rates and deployment the reduction in opex cost is expected to be 2.4% by 2020, 4.6% by 2025 and 5.1% by 2030.

Table 6 Onshore Wind (UK) Operating Cost Forecast 2015 – 2030 (UK), 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	41	40	40	39
Medium	42	41	41	40
High	93	91	89	89

4.4 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these to DECC's current assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Table 7 provides the current cost estimates for 2015, the DECC assumptions comparator and percentage change.

DECC's current assumptions provide an estimate of cost at the UK level. To generate a comparison Arup used DECC's *"Onshore Wind UK"* cost estimate assumptions and compared them with those generated by the analysis. New and old cost estimates for: pre-development, construction; infrastructure; and operating cost are presented below. The following provides Arup's view on what has caused the change in cost between the 2010 study and 2015 cost update:

- **Pre-development cost:** stakeholders indicated that consenting, planning and finding suitable sites is becoming increasingly difficult along with the timescales involved in planning. In addition the timescales required to carry out technical development is reported to have increased along with the requirements for concessions and studies. Overall, the increase in planning timescales and additional requirements has increased the cost of developing onshore wind projects. The overall change was estimated to be quite small at around **2%**.
- **Construction cost:** following a review of the stakeholder data Arup understand that the key drivers of cost include changes in exchange rates; steel; copper; labour; transportation; and grid connection costs. A large reduction in construction cost is reported across all regions and is understood to be driven by improvements in deployment and supply chain efficiency. The change in cost followed Arup's expectation that cost in the onshore wind sector has been driven by deployment, new investment and expansion of the UK supply chain.
- It should be noted that the historic DECC costs assumption used for LCOE modelling were inclusive of infrastructure cost. Arup's new cost estimate

breaks these out, therefore to provide a direct comparison construction and infrastructure cost should be added together. Overall, the change in capex was estimated to be **-6%**.

- **Operating cost:** following an internal and external review of the operating cost data it was concluded that the estimated change between DECC's current LCOE cost assumptions and the new cost estimates generated by Arup could be expected. The average fall in cost was estimated to be around **30%** when compared to DECC's existing cost estimates.
- Key reasons for reductions in cost include economies of scale and the ability of developers to spread operational costs across a large number of sites and installed capacities. In addition, other important drivers include a movement away from Original Equipment Manufacturers ('OEMs') to the use of internal staff, better understanding of project lifecycle cost and increasing competition within the O&M services supply market.
- Insurance costs were noted as falling considerably when compared with current DECC LCOE assumptions. DECC's current assumption is based upon an early estimate of insurance cost which, following increasing rates of deployment, has fallen. Fundamentally, as the insurance industry has improved its knowledge of the key risks surrounding onshore wind it has led to a reduction in cost as risk has become more efficiently priced. Other factors which have driven insurance cost include competition within the insurance market; improvements in the track record of the project developers; and better understanding of the complexity of onshore projects.

Table 7 Onshore Wind (UK) Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	110	110	110	110
	Construction	£/kW	1,253	1,189	1,149	1,121
	Infrastructure	£'000	3,322	3,322	3,322	3,322
	Total capex	**£/kW**	**1,527**	**1,464**	**1,423**	**1,395**
	Total opex	**£MW**	**42,314**	**41,391**	**40,523**	**40,320**
	Fixed O&M	£/MW	23,284	22,735	22,220	22,100
	Variable O&M	£/MWh	5.2	5.1	5.0	5.0

	Assumption	Unit	2015	2020	2025	2030
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	1,441	1,408	1,376	1,368
	UoS	£/MW	3,109	3,109	3,109	3,109
DECC Current	Pre-development	£/kW	107	107	107	107
	Construction	£/kW	1,514	1,464	1,426	1,389
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**1,621**	**1,571**	**1,533**	**1,496**
	Total opex	**£/MW**	**59,514**	**59,624**	**59,734**	**59,844**
	Fixed O&M	£/MW	38,550	38,627	38,704	38,782
	Variable O&M	£/MWh	5.4	5.5	5.5	5.5
	Insurance	£/MW	3,122	3,128	3,134	3,141
	UoS	£/MW	4,673	4,673	4,673	4,673
% Change	Pre-development	%	2%	2%	2%	2%
	Construction	%	-17%	-19%	-19%	-19%
	Infrastructure	%	-	-	-	-
	Total capex	**%**	**-6%**	**-7%**	**-7%**	**-7%**
	Total opex	**%**	**-29%**	**-31%**	**-32%**	**-33%**

Arup reviewed the estimates it produced against benchmark costs from other renewable market and external reports. The objective was to provide validation of the findings and provide comfort around the observations. To understand the change in cost Arup analysed different development, construction and opex benchmark data for onshore wind. Overall, the following was observed when compared to the Arup 2015 figures:

- **Pre-development costs:** no external benchmark was available therefore Arup validated these figures using internal data only.
- **Construction costs:** comparator data were available from EIA, BNEF and NREL which estimated the range of cost to be £1,471/kW, £1,240/kW and £1,131/kW respectively. The 2015 estimate of £1,253/kW sits close to the middle of the external cost range, reflecting the trend in cost reduction Arup has observed[21]. The change in cost reflects Arup's expectation that cost in the onshore wind sector is driven by capacity deployment and expansion of the UK supply chain.
- **Operating cost**: data were available from the EIA and NREL which indicated operating cost to be £26,288/MW and £33,350/MW. Arup's 2015 update is less than DECC's current estimate but above the values provided via external reports. It was concluded that the operating cost values produced by the dataset was potentially higher but followed the observed trend. Arup expected falling operating cost as a result of deployment, competition within the O&M sector and improved supply chains.

4.5 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC's current technical assumptions. The following observations were made:

- **Net power:** At the UK level the average scale of plant has reduced from 71.8MW to 20MW. The change was understood to reflect the availability of large-scale sites and a movement towards smaller sites with higher load factors than previous.
- **Availability:** it is understood that the typical availability for an onshore wind installation is around 97%, allowing for downtime, parts replacement and maintenance inspections. The new assumption replaced DECC's 100% availability assumption.
- **Load factors:** following engagement and a review of stakeholder responses Arup understand that load factors at onshore wind sites are reported to have improved (reflected in our load factor analysis). Developers have over the last five years become better at identifying sites which has led to an overall improvement in load factor. In addition, manufacturers have continued to improve turbine design which has also helped to improve load factor. On a net basis i.e. taking into account plant availability, load factors have increased from around 28% to 32%. The new estimate produced by Arup takes into current and planned sites going forward.

[21] The World Energy Outlook (2014) "450" scenario has forecast onshore wind cost in Europe to fall from £1,259/kW ($1,790/kW, 2012) to £1,125/kW ($1,600/Kw) by 2035. A fall of 42% over 23 years. Assumed 1USD = 0.7035 GBP.

- A summary of the load factor going forward between 2015 and 2030 is presented in **Appendix B.** Overall, for LCOE modelling it has been assumed that the average gross load factor will continue to be at 32.6%.

Table 8 Onshore Wind (UK) Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	71.80	20.20	-51.60
Availability	%	100.0%	97.0%	-3.0%
Load factor (gross)	%	27.6%	32.6%	18.3%
Load factor (net)	%	27.6%	31.7%	14.7%

Table 9 Assumed UK Load Factor %

%	UK
Medium, gross	32.6%
Medium, net	31.7%

Arup's dataset of 42 projects was spread over the time period 2011 to 2021. The minimum, average and maximum load factor from stakeholder responses was calculated for projects commissioning in or around 2015. For the 2020 load factor we assumed the average, minimum and maximum of load factors from stakeholders' responses for projects commissioning in or around 2020. The medium value was the average of load factors – calculated excluding outliers.

4.6 Levelised Cost

Based on the learning rate forecast, capital and operating cost profiles Arup calculated LCOE for an onshore wind reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. The assumed gross load factors for the UK is presented below on table 10, the assumed installation lifetime is 24 years. Table 11 provides the LCOE results based on DECC's updated hurdle rate for the technology.

Table 10 Onshore Wind (UK) LCOE 2016 – 2030, 2014 Real Prices*£/MWh

£/MWh	2016	2020	2025	2030
Low	47	48	46	45
Medium	63	64	62	61
High	76	77	75	74

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table.*

Table 11 LCOE 2016 – 2030 (Onshore wind >5MW, UK), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	46	47	46	45
Medium	62	63	61	60
High	75	76	74	72

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4.7 Comparison of DECC and Arup LCOE Values

The following summary tables provides a comparison between LCOE based on Arup’s new cost data, DECC’s current assumptions and discount rates. For comparison it should be noted that DECC’s figures have been inflated from 2012 to 2014 prices.

Overall, at the UK level the data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE of around 25% less than current DECC figures[22]. Key cost and technical drivers include falls in capital and operating cost and a large increase in load factor.

[22] Please see Department of Energy and Climate Change, Electricity Generation Costs (December 2013)

Table 12 Onshore Wind (UK) Comparison Arup vs. DECC, 2014 Real Prices £/MWh

	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	47	48	69	69	-31.6%	-31.1%
Medium	63	64	84	85	-25.4%	-24.9%
High	76	77	103	104	-25.9%	-25.4%

5 Offshore Wind

5.1 Introduction

In 2015 there is approximately 5.5GW of offshore wind installed or under construction in the UK with 10GW forecast to be delivered by 2020. Large-scale deployment of the technology and programmes to promote technical innovation has led to a reduction in cost.

The first offshore wind in the UK commenced operation in 2000. Since then the sector has continued to develop via a series of licensed ‘Rounds’ that are coordinated via the Crown Estate. The first Round was launched in 2001 and involved around 20 sites. In 2003 Round Two started with projects being located further from shore and in deeper water when compared to the first. Round Three commenced in 2010 and is the biggest round in capacity terms and split across nine zones of the UK. Projects under Round Three are expected to begin construction from 2015.

The 2011 Arup report estimated generation cost and technical performance data for projects being developed at three scales: <100MW, >100MW and Round Three.

To provide an increased level of detail Arup asked stakeholders for additional information on geographical factors such as offshore round, distance from shore and depth of water. Analysis of the stakeholder data suggested that the presentation of cost data for Round Three is most representative for projects delivered by 2020 and beyond. Therefore the analysis carried out in this chapter only provides analysis of Round Three projects. It should be noted that the Crown Estate could in future release additional sites that are easier to develop. If new easier to develop sites are released then the cost data and analysis provided in this would not be representative for Round Three.

In addition, information was collected from publically available industry reports, stakeholders, equipment manufacturers and utilities. On the whole stakeholders were willing to provide data on projects. Stakeholders typically assumed that project operational life ranged between 19 and 24 years.

5.2 Data Collection

Data was also collected from a broad mix of public, internal and stakeholder sources. For the data collection process Arup contacted manufacturers, projects developers and utility companies. Overall, data was collected from internal sources and 5 developers yielding 15 project data points.

Based on the data collection criteria outlined in Chapter 3, 12 data points were assessed to be robust, representative and useful to the analysis. Data for Round Two and Three was evenly split with 6 data points each. For greater than and less than 30km from shore the split was 4 and 8 respectively, for water depths less than and greater than 30m the data was split 5 and 7 respectively.

Although the overall data set was quite small it was assessed to be representative for offshore wind as a whole. All results produced by the analysis were compared against the original stakeholder data and collated benchmarks.

In terms of installed capacity the 15 data points collected represented 8,038MW of projects at various stages of development (operational, under construction and planned). Post evaluation, the final 12 data points used for the analysis had an estimated capacity of 6,993MW. Based on the available data average plant size ranges from a low of 606MW to a high of 1,085MW, the medium installed capacity was calculated to be 844MW.

5.3 Project Costs

Turbine and foundation costs represent a significant proportion of total construction cost, onshore grid connections make up most of the residual cost. It should be noted that for consistency purposes and to avoid double counting, significant grid connection costs have been excluded, taking into account that the cost of Offshore Transmission Owner (‘OFTO’) will be recouped by the transmission asset owner via a charge to the user. These OFTO usage costs have been included via the operating cost.

For Round Three pre-development costs varied significantly from £0.06m/MW to £0.2m/MW. These costs include pre-licencing costs, technical design development costs, regulatory and environmental compliance reporting. Costs were expected to vary significantly depending on the site specific conditions, planning hurdles and requirements for appeal.

The construction costs (excluding pre-development and infrastructure cost) of offshore wind projects ranged from £2.1m/MW to £2.7m/MW with a mean cost of £2.4m. The low end of the cost range is likely to represent projects that are being developed closer to shore and where build conditions at the site is more certain, allowing developers to report lower cost with a greater degree of confidence.

The majority of the capital expenditure is spent on the construction and turbine contracts for delivery. Infrastructure costs are assumed to include onshore transformer stations, connection and associated electrical infrastructure but excluding OFTO infrastructure connections costs. These costs were observed to range from £0.33m/MW to £0.44m/MW with a medium value of £0.38m/MW.

Combing the pre-development, construction and infrastructure cost figure together provides the following capital costs in table 13.

Table 13 Offshore Wind (Round Three) Capital Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000/MW	Round Three
Low	2,456
Medium	2,879
High	3,365

Table 14 Offshore Wind (Round Three) Capital Cost Breakdown for a Medium Project %

%	Round Three
Pre-development	4.3%
Construction	82.4%
Infrastructure	13.3%

5.3.1 Capital Cost Learning Rate Assumption and Forecast

Stakeholders indicated their views of what is considered to be the main drivers of change. The main reported cost drivers included changes to exchange rates, labour and standardisation across the industry. Combined, these factors are expected to put downward pressure on turbine costs. Industry learning continues to be the primary cause for expected decreases in turbines, foundations and deployment costs.

Based on feedback from stakeholders, Arup divided the capex costs into the main costs of project development including turbine, foundation and cables. The change in turbine costs and foundation costs were assumed to have a learning rate which is linked to global deployment. Additionally, we considered other cost factors such as distance from shore and water depth for categories such as foundations. It should be noted that for Round Three Arup relied primarily on learning rate information collected via the literature review.

Arup sought an external view on cost as part of its validation process, providing important experience and knowledge of the renewable technologies. Importantly the review of offshore wind has indicated an alternative view on the technology. For example, The IEA's World Energy Outlook (2014) "450" scenario has forecast a 42% reduction between 2015 and 2035. Therefore, taking into account the divergence in opinion and the pace of historic cost reduction, there is potential for additional cost reductions beyond those identified by the Study.

Appendix C, provides a summary of the cost index forecast for offshore wind. Based on an analysis of learning rates and deployment the reduction in cost is expected to be 8% by 2020, 14% by 2025 and 19% by 2030, which is equal to an annual reduction of -1.4%. The learning rates has been estimated based on data from stakeholders, the IEA and UK offshore wind reports. To obtain our rate 18.7GW of offshore wind is expected to be deployed by 2030.

Table 15 Offshore Wind (Round Three) Capital Cost Forecast 2015 – 2030 (Round Three), 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	2,456	2,298	2,157	2,067
Medium	2,879	2,696	2,535	2,432
High	3,365	3,155	2,969	2,850

The 'medium' construction cost value for Round Three is noted as being low relative to the current DECC assumption: £2.4m/MW compared to £2.5m/MW. Firstly, DECC's current cost estimate for LCOE modelling contains infrastructure costs, although they are not explicitly separated or presented within the LCOE model the Arup estimate does separate the two. If the Arup estimate combines both construction and infrastructure costs together, the total cost is equal to £2.9m/MW.

Arup's learning rate forecast has been applied to construction costs only. For modelling purposes and consistency with previous work, pre-development and infrastructure costs are assumed constant.

5.4 Operating Cost

Operating costs for offshore wind comprise of fixed and variable O&M contracts, UoS charges, insurance and labour. The following table illustrates the variation in cost at all levels of disaggregation. Operating costs vary quite significantly which is understood to be driven by: local conditions such as availability of labour within the local market; availability of transportation vessels; local grid charges; price; and availability of components.

Table 16 below provides an indication of the variation in operating cost between categories. For Round Three cost ranges from £84k/MW to £152k/MW, with a mean of £117k/MW.

Table 16 Offshore Wind (Round Three) Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000/MW	Round Three
Low	84
Medium	117
High	152

5.4.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs Arup divided the learning rate forecast into categories: fixed O&M; variable O&M; insurance; and grid costs. For grid costs Arup assumed the OFTO transfer fee which will be dependent upon construction cost of the transmission connection; for fixed and variable O&M we used opex learning rates from literature; insurance costs were assumed to be linked to the changes in capex costs.

For operating costs stakeholders identified labour and availability of components as an important cost driver. Stakeholders indicated an expectation for operating costs to remain broadly flat with some potential for opex cost reductions.

Appendix C, provides a cumulative summary of the cost index forecast applied to offshore wind Round Three. Based on an analysis of learning rates and deployment the reduction in opex cost is expected to be 6% by 2020, 7.1% by 2025 and 6% by 2030. It should be noted that insurance, fixed and variable O&M costs are expected to continue and fall across the forecast period. However, post-2025 the effect of increasing OFTO cost is expected to be greater than the estimated fall in insurance, fixed and variable O&M.

Table 17 Offshore Wind (Round Three) Operating Costs Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	84	81	81	81
Medium	117	114	113	114
High	152	148	147	148

5.5 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these with DECC's existing assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Table 18 provides current cost estimates for 2015, the DECC assumptions comparator and percentage change.

Arup has used DECC's existing cost estimates and compared these to those generated by the updated analysis. New and old cost estimates for: pre-development; construction; infrastructure; and operating cost presented below. The following provides Arup's view on what has caused the change in cost between the 2010 study and 2015 cost update:

- **Pre-development cost:** stakeholders reported that the increases in cost were partially driven by increasingly stringent Environmental Impact Assessments ('EIA'), geotechnical surveys, consenting and obtaining land rights. In general, it is Arup's expectation that there should be economies of scale in pre-development planning. For example, planning teams for Round Two and Round Three projects will normally be of a similar scale, therefore it can be expected that as the installed capacity increases from Round Two to Round Three, the cost on a £/kW basis should decrease.
- It should be noted that the Round Three costs are for future projects under development and are expected to contain a large amount of contingency relative to Round Two estimates.
- **Construction cost:** for Offshore Round Three a comparison of the construction costs indicate an increase in cost between DECC LCOE figure and the Arup 2015 figures. Overall, when all costs are combined (construction plus infrastructure) the costs for Round Three is **9%** higher than DECC's figure reflecting new cost estimates of moving away from shallower to deeper waters. In addition, it is also understood that larger turbine sizes at Round Three sites (4MW to 6MW turbines) are expected to be the norm, which will also have had a positive impact on the overall cost.
- The change in construction cost for Round Three therefore reflect of our expectation for future changes in cost. It should be noted that although construction costs have increased, the expected increase in load factor for Round Three is likely to offset any potential increase in levelised cost through increases in electrical output.
- It is reported that key drivers of future costs will include availability of vessels, helicopters, specialists, replacement parts; network charges; vessels for larger size turbines and equipment; sufficient production facilities for jackets; and lead times for cables.
- **Operating cost:** for Round Three there is a reported large reduction in total opex driven by falls in fixed, variable and insurance costs. Firstly the improvement in cost potentially reflects improvements in cost certainty and a better understanding of how the assets can be expected to operate. Secondly it also reflects an increase in competition within the offshore wind sector and its

positive impact on the pricing of O&M services. Finally, the change in cost is also reflective of a movement away from OEMs toward independent and in-house O&M service providers.

- Insurance costs were noted as increasing when compared to DECC's LCOE assumptions. DECC's current assumption is based upon an early estimate of insurance cost. Since the first projects were developed capex costs have continued to increase, primarily driven by project development factors including increasing distances from shore, longer repair and maintenance timing of construction equipment, depth and seabed conditions. Fundamentally, as the insurance industry has improved its knowledge of the key risks around offshore wind, the result has been an overall increase in cost as risk has become more efficiently priced.

Table 18 Offshore Wind (Round Three) Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	125	125	125	125
	Construction	£/kW	2,371	2,189	2,028	1,924
	Infrastructure	£'000	323,030	323,030	323,030	323,030
	Total capex	**£/kW**	**2,879**	**2,696**	**2,535**	**2,432**
	Total opex	**£MW**	**117,125**	**113,589**	**112,950**	**113,605**
	Fixed O&M	£/MW	48,623	45,701	45,174	45,715
	Variable O&M	£/MWh	1.6	1.6	1.5	1.6
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	3,349	3,147	3,111	3,148
	UoS	£/MW	50,331	50,331	50,331	50,331
DECC Current	Pre-development	£/kW	107	107	107	107
	Construction	£/kW	2,540	2,452	2,371	2,221
	Infrastructure	£'000	0	0	0	0

	Assumption	Unit	2015	2020	2025	2030
	Total capex	**£/kW**	**2,647**	**2,560**	**2,479**	**2,328**
	Total opex	**£/MW**	**163,585**	**144,887**	**134,890**	**127,840**
	Fixed O&M	£/MW	66,207	53,426	46,592	41,773
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£/MW	30,646	24,729	21,566	19,336
	UoS	£/MW	66,732	66,732	66,732	66,732
% Change	Pre-development	%	16%	16%	16%	16%
	Construction	%	-7%	-11%	-14%	-13%
	Infrastructure	%	-	-	-	-
	Total capex	%	**9%**	**5%**	**2%**	**4%**
	Total opex	%	**-28%**	**-22%**	**-16%**	**-11%**

Arup reviewed the estimates it produced against benchmark costs from other renewable and external market reports. The objective here was to provide validation of the findings and provide comfort around the observations. To understand the change in cost Arup analysed different development, construction and opex benchmark data for offshore wind Round Three. Overall, the following was observed when compared to the Arup 2015 figures:

- **Construction costs:** comparator data was available from BNEF which estimated the cost for ‘offshore wind’ to be £3,195/kW. The 2015 estimate of £2,879/kW is below the offshore wind cost estimate. Arup is confident that the Round Three value is representative since it is based on stakeholder data and has been validated internally.

- **Operating cost**: data was available from BNEF which indicated that for ‘fixed’ O&M cost a value of £77,934/MW can be expected. The updated value is less than the DECC’s current estimate which is close to the BNEF figure. It was therefore concluded that the 2015 Update figure displayed the expected trend of falling cost as result of deployment, competition within the O&M sector and improved supply chains. The benchmark value did not follow the expected change as indicated by the stakeholders. For the analysis Arup has therefore discounted the benchmark figure and used its own estimate based on the stakeholder information.

5.6 Technical Assumptions

Based on the data received from stakeholders Arup was able to carry out a comparison with DECC's current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net power:** overall for Round Three projects there is a small 11MW reported increase in expected wind farm size, indicating greater certainty of future deployment.
- **Availability:** it is understood that Round 3 availability has improved marginally from 95.2% to 95.7%. The increases reflect the improvements in the way offshore developers are operating their assets and O&M regimes.
- **Load factors:** Arup understand that load factors at offshore wind sites are reported to have improved significantly relative to existing DECC assumptions. The current trend across the global offshore wind industry is for steadily improving load factors; Anholt 1 (Denmark) has recently reported a 50% load factor[23]. Overall for Round Three projects the central net load factor is reported to have improved from 39.5% to 47.7%. Arup has assumed for Round Three that the earliest project commissioning will be in 2020 and a constant net load factor of 47.7% thereafter.
- A summary of the load factors assumed between 2015 and 2030 is presented in **Appendix B.** Overall, for LCOE modelling it has been assumed that the average gross load factor will be 49.8% gross.

Table 19 Offshore Wind (Round Three) Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	833.00	844.33	11.33
Availability	%	95.2%	95.7%	0.5%
Load factor (gross)	%	41.5%	49.8%	20.1%
Load factor (net)	%	39.5%	47.7%	20.7%

[23] Please see: http://energynumbers.info/capacity-factors-at-danish-offshore-wind-farms

Table 20 Offshore Wind (Round Three) Assumed Load Factor (%)

%	Round Three
Medium, gross	49.8%
Medium, net	47.7%

Arup has carried out a review of the latest load factor data provided by stakeholders, internal and external sources and generated an average value for Round Three projects. The value has been internally reviewed and is appropriate for the type of projects expected to be delivered in the future.

Due to limited stakeholder data Arup developed a time series of Round Three projects. Arup applied RenewableUK's load factor assumption and forecast to 2015 for the medium and high. For the low 2015 Arup used DECC's Electricity Generation Costs 2013 load factor. For 2020 the average, minimum and maximum load factor for Round 3 projects was calculated, based on the responses from stakeholders for projects commissioning in or around 2020.

5.7 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for an offshore wind reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. The assumed gross load factors for Round Three projects are presented on table 20 and the assumed medium lifetime is 22 years. Tables 22 provides the LCOE results based on DECC's updated hurdle rate for the technology.

Table 21 Offshore Wind (Round Three) LCOE 2016 – 2030, 2014 Real Prices*£/MWh

£/MWh	2016	2020	2025	2030
Low	94	99	93	90
Medium	107	112	106	102
High	121	127	120	116

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table.*

Table 22 LCOE 2016 – 2030 (Offshore Round 3), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	89	93	88	85
Medium	101	106	100	96
High	114	119	113	109

5.8 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup’s new cost data, DECC’s current assumptions and discount rates. Overall, at Round Three level the data indicates that a project commissioning by 2020 will have an LCOE 17% less than current DECC figures. Key cost and technical drivers include a small fall in capital cost and operating cost and a large increase in load factor. It is reasonable to assume that costs could fall more quickly if, for example, the Crown Estate released more development sites closer to shore and in shallower waters. In addition, targeted innovation programmes could support further reductions[24]. For comparison it should be noted that DECC’s figures have been inflated from 2012 to 2014 prices.

Table 23 Offshore Wind (Round Three) Comparison Arup vs. DECC, 2014 Real Prices £/MWh

	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	94	99	112	119	-16.0%	-16.9%
Medium	107	112	129	136	-17.0%	-17.3%
High	121	127	151	158	-19.4%	-19.2%

[24] Please see: Low Carbon Innovation Coordination Group, Technology Innovation Needs Assessment (‘TINA’), Offshore Wind Power Summary Report (2012).

6 Solar

6.1 Introduction

Solar power in the United Kingdom ('UK') has increased rapidly in recent years as a result of a reduction in the price of photovoltaic cells and the introduction of support mechanisms. Projects are located all over the country, but with highest concentration in the South of England where the best solar insolation can be achieved.

Central to the deployment of PV has been the reduction in component costs at the global level, deployment and improvements in the UK supply chain. Compared to historic forecasts, the rate of cost reduction within the sector has generally outperformed expectation. To add to the analysis Arup has also reviewed published and internal sources of data.

For the Arup 2011 study DECC had previously requested that the data was collated for ranges that included: <50kW; 50kW-5MW; 5MW-10MW and >10MW. For this Study Arup has collected data on two categories of solar, reflecting scale of plant and location:

- PV > 5MW
- PV 1 to 5MW, ground mounted.
- PV 1 to 5MW, building mounted.

It should be noted that there was a limited number of responses from stakeholders. There was a notable lack of data for PV building mounted systems. Where there was a shortage of data Arup has used data from alternative published sources, benchmarks and size categories that are close to the scale under review. Stakeholders typically assumed a typical technical life of 25 years.

6.2 Data Collection

Data was collected from stakeholders, internal and published sources. For the data collection process Arup contacted manufacturers, developers, trade associations and utility companies. Overall data was collected from internal projects and 6 developers, yielding 20 project data points.

Based on the data collection criteria outlined in Chapter Three, 13 data points were assessed to be robust, representative and useful to the analysis. At the PV>5MW, PV 1-5MW (ground) and PV 1-5MW (building mounted) level, 5, 3 and 5 data points were available respectively. All results produced during the analysis were compared with the original stakeholder data and collated benchmarks.

In terms of installed capacity the initial 20 data points collected represented 99.7MW of projects at various stages of development (operational, under construction and planned). Post-evaluation the final 13 data points used for the analysis had an estimated capacity of 97.7MW (the seven projects removed had a combined installed capacity of 2MW).

6.3 Project Costs

Panels form the largest proportion of total construction cost at around 45%, grid connections and racks also represent a significant item. The pre-development costs varied between PV categories ranging from £74/kW to £15/kW for a PV>5MW to PV 1-5MW building mounted system respectively. Pre-development includes pre-licencing, technical design development and regulatory reporting. Costs are expected to vary significantly depending on the site specific conditions, planning hurdles and requirement for appeals.

The medium construction cost for PV>5MW, PV 1-5MW ground and building are £802/kW, £884/kW and £867/kW respectively. Developers reported that they are continuing to experience cost reductions related to the roll-out of plant from improved efficiency in deployment and site selection. The majority of the capital expenditure is spent on panels, electrical infrastructure and racking equipment. Infrastructure costs are reported to be £62/kW to £54/kW for PV 1-5MW ground and building respectively. Table 24 provides the estimated capital costs which are a summary of pre-development, construction and infrastructure

Table 24 Capital Costs (Financial Close 2015), 2014 Real Prices £'000/MW[25]

£'000/MW	PV >5MW	PV 1 – 5MW (ground)	PV 1 – 5MW (building)
Low	784	866	844
Medium	900	1,007	936
High	1,067	1,156	1,071

Table 25 Capital Cost Breakdown for a Medium Project %

£'000/MW	PV >5MW	PV 1 – 5MW (ground)	PV 1 – 5MW (building)
Pre-development	8.2%	5.9%	1.6%
Construction	89.0%	87.9%	92.6%
Infrastructure	2.8%`	6.2%	5.7%

[25] A recent survey of building mounted and utility scale PV by the Grantham Institute indicates that the current cost estimate to be around £1,000/kW.

6.3.1 Capital Cost Learning Rate Assumption and Forecast

Stakeholders indicated their views of what is considered to be the main cost drivers. The main drivers included changes to panel prices, inverter, exchange rates, labour and standardisation across the industry.

Based on the questionnaire stakeholders expect costs to continue and fall for panels and inverters. In addition, other factors such as growth within the UK supply chain, project pipeline and improvements in manufacturing efficiency are all expected to improve cost.

Combined these factors are expected to put downward pressure on construction cost in the future. Industry learning driving down price continues to be the primary cause for expected decreases in cost. **Appendix C**, provides a summary of the cost index forecast for all types of PV plant. Based on an analysis of learning rates and deployment the reduction in cost is expected to be 22% by 2020, 27% by 2025 and 31% by 2030, which is equal to an annual reduction of -2.4%. The learning rates has been estimated based on data from stakeholders, the IEA, the STA and UK focussed literature review. To obtain our rate 18.3GW of PV is expected to be deployed by 2030

To understand the expected change in construction cost Arup has analysed different learning rates for construction cost, focussing primarily on our expectations for changes in module and balance of system costs. Module cost reductions were linked to global deployment and balance of system linked to UK deployment. Arup has also applied the cost reduction factors produced by the Solar Trade Association (‘STA’) to other capex cost components, such as racks and onsite electrical infrastructure, including those in the final reduction factor calculation. Tables 26 to 28 provides Arup’s forecast of cost reduction to 2030.

Table 26 PV > 5MW Capital Cost Forecast 2015 – 2030, 2014 Real Prices £’000/MW

£’000s/MW	2015	2020	2025	2030
Low	784	622	580	551
Medium	900	728	683	652
High	1,067	880	832	798

Table 27 PV 1-5MW, Ground Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	866	704	662	633
Medium	1,007	816	767	733
High	1,156	936	879	839

Table 28 PV 1-5MW, Building Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	844	676	633	603
Medium	936	750	701	668
High	1,071	857	802	763

Arup's learning rate forecast has been applied to construction cost only. For modelling purposes and consistency with previous work, pre-development and infrastructure costs are assumed to be constant.

6.4 Operating Costs

For operating costs Arup divided the cost forecast into categories: fixed and variable O&M, insurance, and grid costs. The operating cost reduction factor takes into account the STA's opex cost reduction factor. A comparison between the learning rates produced by the STA and those reported by the stakeholders were found to be very close. Operating costs comprise of fixed and variable O&M contracts, UoS charges, insurance and labour. The following table illustrates the variation in cost for each type of PV system.

Operating costs will vary significantly depending on the type of O&M services procured, local conditions such as availability of labour within the local market, local grid charges, price and availability of components. Overall, the O&M cost produced via the stakeholder data is within the range Arup expected £10k/MW to £20k/MW. Table 29 below provides an indication of the variation in operating cost between categories. For all categories, cost ranges from £10k/MW to £16k/MW. At the high end, building mounted PV operating costs appear to be most expensive. It should be noted that O&M costs excluded land costs, rent etc (please see the definitions outlined in Chapter Three), which explains the difference between Arup's figure and those produced by the STA.

Table 29 Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000/MW	PV >5MW	PV 1 – 5MW (ground)	PV 1 – 5MW (building)
Low	9	8	9
Medium	10	12	16
High	14	18	24

6.4.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs stakeholders identified labour and availability of components as an important cost driver. Broadly stakeholders did indicate that they expect operating costs to remain flat with some potential for additional reduction.

Appendix C, provides a summary of the cost index forecast applied to all PV categories. Based on an analysis of learning rates and deployment the reduction in operating cost is expected to be 17% by 2020, 22% by 2025 and 26% by 2030.

Table 30 PV > 5MW Operating Costs Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	9	8	7	7
Medium	10	9	8	8
High	14	12	12	11

Table 31 PV 1-5MW, Ground Operating Costs Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	8	7	7	6
Medium	12	11	10	10
High	18	16	15	14

Table 32 PV 1-5MW, Building mounted Operating Costs Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	9	8	7	7
Medium	16	13	12	12
High	24	20	19	18

6.5 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these to DECC's current assumptions. The objective of the analysis was to identify where costs have changed and understand what is driving the change. Tables 33 to 35 below provide current cost estimates for 2015, the DECC assumptions comparator and percentage change. It should be noted that the cost data collected is for PV projects that have commenced operation or under development.

In Table 33 below, current DECC assumptions refer to 250-5000kW large scale solar plants. Only one DECC comparator was available and the category made no distinction between ground and building mounted plants, unlike the new data.

The costs shown under '2015 current figures' below include cost reductions previously assumed by DECC for plants that reach FID in 2015, in order to ensure that this is a like for like comparison with the new 2015 data.

Arup has prepared estimates of cost for PV>5MW, PV 1-5MW ground based and PV 1-5MW building installed. New and old cost estimates for: pre-development; construction; infrastructure; and operating cost are presented below. The following provides Arup's view on what has caused the change in cost:

- **Pre-development cost:** it should be noted that no pre-development cost data was available for comparison with the Arup 2015 figure. Therefore, in the absence of any benchmark data Arup has continued to use the pre-development cost data provided by stakeholders.

- **Construction cost:** the current estimated construction cost of £802/kW to £884/kW is within Arup's expected cost range of £800/kW to £900/kW. The estimate was derived from stakeholder data and has reduced relative to DECC's current assumption. The change in cost reflects reductions in panel and inverter prices. Discussions with stakeholders also indicated that further cost reductions could be expected if *"EU dumping"* regulations were to be removed in the future. In addition the STA has also indicated that PV cost reductions have historically outperformed expectation from Government and industry[26].

- **Operating cost:** following an internal and external review, total operating cost appears to be at the low end of the expected cost range. For example, Arup would typically expect the annual opex cost to range from £10k/MW to £20k/MW.

- The Arup 2015 figure is significantly less than the current assumption of £23k/MW and the Solar Trade Association (STA) figure of £26k/MW. The current figures reported by the stakeholders were based on real reported figures. However, the information received was noted as being provided by large-scale developers which could be experiencing a large reduction in opex cost due to economies of scale and the ability to spread cost across a greater number of sites. It should be noted that the Arup estimate does not include land cost, rental or community payments. These costs are understood to be included within the STA's estimate.

- Since the first large-scale PV farm installations began in 2009/2010, opex costs have continued to fall as a result of a movement away from Original Equipment Manufacturers ('OEMs'), with a trend toward more 'in-house' engineering.

[26] Solar Trade Association, Cost Reduction Potential of Large Scale Solar PV – An Analysis Into The Potential Cost Reductions That The UK Solar Industry Could Deliver to 2030 With Stable Policy Support, November 2014

Table 33 PV >5MW Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	74	74	74	74
	Construction	£/kW	802	629	584	553
	Infrastructure	£'000	414	414	414	414
	Total capex	**£/kW**	**900**	**728**	**683**	**652**
	Total opex	**£MW**	**10,350**	**8,866**	**8,393**	**8,033**
	Fixed O&M	£/MW	6,495	5,404	5,056	4,792
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	2,342	1,949	1,824	1,728
	UoS	£/MW	1,513	1,513	1,513	1,513
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	1,060	850	693	565
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**1,060**	**850**	**693**	**565**
	Total opex	**£/MW**	**23,453**	**22,586**	**22,586**	**22,586**
	Fixed O&M	£/MW	23,453	22,586	22,586	22,586
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
	Pre-development	%	-	-	-	-

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	-24%	-26%	-16%	-2%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-15%**	**-14%**	**-1%**	**15%**
	Total opex	%	**-56%**	**-61%**	**-63%**	**-64%**

Table 34 PV 1-5MW Ground Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	60	60	60	60
	Construction	£/kW	884	694	645	611
	Infrastructure	£'000	221	221	221	221
	Total capex	**£/kW**	**1,007**	**816**	**767**	**733**
	Total opex	**£MW**	**12,458**	**10,620**	**10,033**	**9,588**
	Fixed O&M	£/MW	9,577	7,968	7,455	7,066
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	1,368	1,138	1,065	1,009
	UoS	£/MW	1,513	1,513	1,513	1,513
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	1,060	850	693	565
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**1,060**	**850**	**693**	**565**

	Assumption	Unit	2015	2020	2025	2030
	Total opex	**£/MW**	**23,453**	**22,586**	**22,586**	**22,586**
	Fixed O&M	£/MW	23,453	22,586	22,586	22,586
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
% Change	Pre-development	%	-	-	-	-
	Construction	%	-17%	-18%	-7%	8%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-5%**	**-4%**	**11%**	**30%**
	Total opex	%	**-47%**	**-53%**	**-56%**	**-58%**

Table 35 PV 1-5MW Building Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	15	15	15	15
	Construction	£/kW	867	681	632	599
	Infrastructure	£'000	36	36	36	36
	Total capex	**£/kW**	**936**	**750**	**701**	**668**
	Total opex	**£MW**	**15,526**	**13,173**	**12,422**	**11,852**
	Fixed O&M	£/MW	7,629	6,348	5,939	5,628
	Variable O&M	£/MWh	3.4	2.9	2.7	2.5
	BSUoS	£/MWh	0.0	0.0	0.0	0.0

	Assumption	Unit	2015	2020	2025	2030
	Insurance	£MW	3,068	2,553	2,388	2,264
	UoS	£/MW	1,513	1,513	1,513	1,513
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	1,060	850	693	565
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**1,060**	**850**	**693**	**565**
	Total opex	**£/MW**	**23,453**	**22,586**	**22,586**	**22,586**
	Fixed O&M	£/MW	23,453	22,586	22,586	22,586
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
% Change	Pre-development	%	-	-	-	-
	Construction	%	-18%	-20%	-9%	6%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-12%**	**-12%**	**1%**	**18%**
	Total opex	%	**-34%**	**-42%**	**-45%**	**-48%**

Arup reviewed the estimates it produced against benchmark costs from other renewable market reports. The objective was to provide validation of the findings and provide comfort around the observations. To understand the change in costs Arup analysed different development, construction and opex benchmark data for PV. Overall, the following was observed when compared to the Arup 2015 figures:

- **Construction costs:** comparator data was available from STA which estimated cost to be £1.03m/MW. The Arup 2015 estimates include pre-development, construction and infrastructure are £0.90m/MW, £1.01m/MW and £0.94m/MW approximately 2% to 12% lower than the external benchmark cost. Post-evaluation and internal review Arup was comfortable with the figures generated by the analysis despite being lower than the external benchmark.

- **Operating cost**: data was available from the STA which indicated cost to be around £26k/MW and understood to include costs Arup has not (lease costs, business rates etc.). Arup's 2015 update is less than DECC's and the STA's estimate. Based on internal benchmark data it was concluded that the operating cost value produced by the dataset was potentially low but followed the trend Arup expected and matched observed cost from projects. Therefore, the stakeholder data has been used for the analysis.

6.6 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC's current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net Power:** since 2010 the overall average installed capacity of a PV development has increased significantly. The current assumption used by DECC is 350kW, significantly smaller than the current average capacity computed to be 16.4MW, 3.5MW and 0.7MW for PV>5MW, 1-5MW ground and building respectively.

- **Availability:** it is understood that the typical availability for a PV installation can be assumed to be 99%; this figure allows for some downtime for part replacement and washing of panels. A comparison with DECC's current assumption indicates a small overall change.

- **Load factor:** When DECC's current load factor is compared to the current load factor reported by stakeholders it is understood to be very close (within 1%) of the current DECC assumption. Arup validated its assumption by contacting stakeholders to find out their expected load factors; overall the load factors reported were close to the current benchmarks from the Solar Trade Association ('STA'). Arup has therefore used 11% as the load factor which is consistent between stakeholder values and published figures.

- Stakeholders typically assumed a technical life of 25 years.

- A summary of the load factor going forward between 2015 and 2030 is presented in **Appendix B.** Overall, for LCOE modelling it has been assumed that the average gross load factor will be 11.11% gross and assumed constant for the forecast period.

Table 36 PV >5MW Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	0.35	16.42	16.07
Availability	%	100%	99%	-1.0%
Load factor (gross)	%	11%	11%	-0.2%
Load factor (net)	%	11%	11%	-1.2%

Table 37 PV 1-5MW Ground Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	0.35	3.55	3.20
Availability	%	100%	99%	-1.0%
Load factor (gross)	%	11%	11%	-0.2%
Load factor (net)	%	11%	11%	-1.2%

Table 38 PV 1-5MW Building Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	0.35	0.67	0.32
Availability	%	100%	99%	-1.0%
Load factor (gross)	%	11%	11%	-0.2%
Load factor (net)	%	11%	11%	-1.2%

The assumed gross load factors for each type of PV system is presented below on Table 39 with an assumed medium lifetime of 25 years, which approximately equates to the warranty period for the PV modules. Arup understands that developers are potentially looking at extending the life of projects out to 40 years. Arup has however not found any evidence to suggest that this will take place, therefore Arup has modelled plants on a 25 year lifetime basis.

Table 39 Assumed PV Category Load Factor (%)

%	PV >5MW	PV 1 – 5MW (ground)	PV 1 – 5MW (building)
Medium, gross	11.1%	11.1%	11.1%
Medium, net	11.0%	11.0%	11.0%

With regard to future load factors our assumption for low and medium scenarios is to keep the load factor constant – in line with stakeholder and literature research views. Arup developed a high scenario where load factor will increase: based on evidence (gathered through our technical experts) that shows how technical change (tracking, HIT etc.) will lead to an increase in load factor. Such technologies are currently expensive but could become more cost competitive, leading to higher load factors by 2020 (please see load factor index in **Appendix B**).

6.7 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for the types of plant listed above for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC’s current hurdle rates. Tables 43 to 45 provide the LCOE results based on DECC’s updated hurdle rate for the technology.

Table 40 PV>5MW LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	60	53	49	47
Medium	68	60	57	54
High	79	71	67	65

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 41 PV 1-5MW, Ground LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	68	60	57	54
Medium	77	68	64	61
High	86	77	72	69

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 42 PV 1-5MW, Building LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	69	61	57	54
Medium	75	66	62	59
High	83	74	69	66

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 43 LCOE 2016 – 2030 (PV >5MW), 2014 Real Prices £/MWh , Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	65	59	55	52
Medium	74	67	63	60
High	87	80	76	73

Table 44 LCOE 2016 – 2030 (PV 1 to 5MW, ground), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	74	67	63	60
Medium	84	76	72	68
High	94	86	81	77

Table 45 LCOE 2016 – 2030 (PV 1 to 5MW, building mounted), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	75	68	63	60
Medium	81	73	69	65
High	91	82	77	73

6.8 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup's new cost data, DECC's current assumptions and discount rates. Overall, for PV the data indicates that a project commissioning by 2020 will have an LCOE that is 35% and 26% less than current DECC figures (depending on scale, ground or building mounted). The key driver is expected to be further reductions in in capital cost and operating costs going forward. For comparison it should be noted that DECC's figures have been inflated from 2012 to 2014 prices.

It should be noted that previously, DECC only reported one large scale solar PV category for 250kW to 5MW sized projects. These estimates are used for all the previous DECC comparators in the following three tables.

Table 46 PV > 5MW Comparison Arup vs. DECC, 2014 Real Prices

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	60	53	97	86	-38.6%	-39.0%
Medium	68	60	104	92	-34.8%	-34.5%
High	79	71	111	98	-28.5%	-27.4%

Table 47 PV 1-5MW, Ground Comparison Arup vs. DECC, 2014 Real Prices

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	68	60	97	86	-30.3%	-30.0%
Medium	77	68	104	92	-26.3%	-25.9%
High	86	77	111	98	-22.5%	-22.0%

Table 48 PV 1-5MW, Building Comparison Arup vs. DECC, 2014 Real Prices

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	69	61	97	86	-29.2%	-29.4%
Medium	75	66	104	92	-28.2%	-28.2%
High	83	74	111	98	-25.2%	-25.1%

7 ACT

7.1 Introduction

Advanced Conversion Technologies ('ACT') are gasification and pyrolysis technologies used to change municipal solid waste ('MSW'), solid recovered fuel ('SRF'), refuse derived fuel ('RDF') and biomass into gas for electricity generation. Through the stakeholder engagement process Arup collected new data related to ACT cost, gate fees, types of technology deployed, waste handling and ACT process in place.

ACT has the potential to deliver efficient generation. Since 2010 the roll-out of gasification and pyrolysis has increased as a result of plants becoming more commercially viable and developers continuing to invest in the technology. There has started to emerge the deployment of large-scale commercial plants with fuel input requirement of >100,000 tonnes. As a result of the technology being at an early stage of development, ACT deployment and generation has continued to face challenges in terms of improving efficiency and securing fuel supply contracts. It is however understood that standardisation in deployment and technology is taking place as learning effects take place.

Gasification is the thermal degradation of waste in a closed system with restricted quantities of air or oxygen at temperatures which are typically in the range of 800°C to 900°C[27]. The process generates a synthetic gas which is known as syngas typically made up of carbon monoxide, carbon dioxide, hydrogen and methane. The gas can be combusted and used to raise steam in a boiler to drive a turbine or injected into an engines or turbine to produce electricity and heat.

Pyrolysis is the thermal degradation of waste in a closed system in the absence of air at temperatures which normally range from 400°C to 800°C. The pyrolysis process generates a syngas rich in hydrogen which can then be used to produce heat and electricity in the same ways described above. The process also produces a bio-oil hydrocarbon liquid and a char solid product. These can be combusted to produce the energy required to reach the high temperatures involved in the pyrolysis process.

Since 2010 there have been over 20 new ACT plants that have been deployed, planned and are now become operational. These plants are operating using a range of processes, input fuel types, hence they produce syngas with a range of calorific values.

The questionnaire issued to each stakeholder asked for specific information around the ACT processes in place to generate electricity:

- The type of ACT process in place.
- The input into the ACT chamber.
- How the gas is used, i.e. whether is it used to generate steam or heat.

[27] Temperature range assumption provided via an external peer review by Imperial College.

- The calorific value of the fuel input being used to generate.

For the analysis Arup split the data between different categories of ACT; 'Advanced', 'Standard' and 'CHP'. The objective was to understand what the differences are in generation cost between the categories. A summary of the criteria agreed with DECC and applied to the ACT data is provided below. There are three main differences between Advanced and Standard forms of ACT, which can be used to disaggregate the data:

- Calorific value ('CV') is a metric that indicates the energy content of fuel (i.e. waste) input used to generate syngas for electricity generation. CV values will typically be higher in Advanced ACT relative to Standard ACT. The main drivers are type of fuel and the fuel handling process in place. Standard ACT will typically use refuse derived fuel ('RDF') whereas Advanced ACT may use a combination of RDF and solid recovered fuel ('SRF'). SRF fuel requires a more thorough fuel recovery process relative to RDF, which allows the removal of imperfections such as glass, metal, rubble etc. A more thorough recovery process should therefore increase CVs of the final gas being used in the ACT. To help categorise Advanced and Standard ACT Arup collected data on the calorific value of the fuel produced and used (MJ/Nm3)[28]. To be classed as an Advanced ACT it the energy content was assumed to be greater than 10MJ/Nm3 and for Standard ACT it was assumed to be less than 10MJ/Nm3.

- The ACT gasification process converts fuel into syngas which can be combusted in gas turbines, engines, turbines and boilers to produce electricity, heat or both via a CHP. Currently the most common form of ACT plant in the UK burns syngas, produces steam via a boiler which drives a turbine to generate electricity. Arup understand that ACT designed to combust syngas into a CHP engine are not as widely deployed. For the analysis it has been assumed that standard forms of ACT include a boiler to generate steam, followed by a turbine generator to produce electricity. Advanced ACT's are assumed to use either a boiler or CHP for heat generation, or a CHP engine for heat and electricity generation.

- In an ACT plant, syngas will typically leave the gasification or pyrolysis chamber at a high temperature. Recovery of heat from syngas is important to ensure optimal plant efficiencies. Therefore, heat recovery systems are installed to reclaim a portion of the energy contained within the useful heat. Advanced forms of ACT will typically have a heat recovery and syngas cooling system in place. In terms of process a heat exchanger will allow the syngas to be cooled, generating high-pressure steam before it is passed through a convective cooler generating medium pressure steam. Syngas is then scrubbed to remove particles and finally cooled again to a lower temperature. For the analysis Advanced ACT is assumed to have equipment that allows both syngas cooling and heat recovery to take place. In general Standard ACT is not expected to have heat recovery equipment installed.

[28] Arup's questionnaire asked ACT owners to indicates the expected calorific value of the fuel being produced in MJ/cbm

The following is a summary of the rules Arup has applied to determine the type of ACT being either Advanced or Standard. The proposed rules were discussed and agreed with DECC and have been applied to the ACT dataset.

Advanced ACT / ACT CHP

- The CV is greater than 10MJ/Nm3.
- Syngas is fed into a gas turbine or used in a CHP engine.
- The process involves a syngas cooling stage and heat recovery.

Standard ACT

- The CV is less than 10MJ/Nm3.
- Syngas is used to generate steam to drive a turbine and produce electricity.
- Syngas cooling and heat recovery is not part of the generation stage.

In addition to the Advanced and Standard forms of ACT outlined above Arup has also split the data based on the fuel input types. These are ACT with RDF inputs and ACT with RDF plus another fuel. The results of the analysis are provided in **Appendix I.** The following provides the final list of how dataset was spilt in the main report:

- ACT, standard
- ACT, advanced
- ACT, CHP

7.2 Data Collection

Data was collected from stakeholders, internal and published sources. For the data collection process Arup contacted equipment manufacturers, developers and trade associations. Overall data was collected from internal sources and 7 developers, yielding an initial 13 project data points.

Based on the data collection criteria outlined in Section 2, 11 data points were assessed to be robust, representative and useful for the analysis. The number of Standard and Advanced ACT data points available were 8 and 3 respectively. All results produced during the analysis were compared with the original stakeholder data and collated benchmarks.

In addition, Arup also contacted stakeholder to collect data on ACT CHP. Unfortunately very limited data was received that could be used for the analysis. Arup has therefore implemented a 'CHP premium' approach to estimate the final cost[29]. To calculate ACT CHP cost Arup initially used the ACT Advanced cost and technical profile, including additional CHP and heat recovery equipment cost.

[29] Please see Arup. October 2011, Review of Generation Costs and Deployment Potential of Renewable Technologies in the UK

CHP costs were estimated to be around 10% of base construction cost and 15%-20% for heat recovery equipment.

In terms of installed capacity the 13 data points collected represented 173MW of projects at various stages of development (operational, under construction and planned). Post evaluation the final 8 data points used for the ACT Standard and 3 data points used for the ACT Advanced analysis had an estimated total capacity of 108MW and 36MW respectively. The data collection included projects between 1MW and 42MW of installed capacity. Following the data analysis and validation process the low and high installed capacity for ACT Standard and ACT Advanced was 8MW to 19MW and 6MW to 13MW respectively. Average capacity was calculated to be equal to 12MW and 9MW for Standard ACT and Advanced ACT, respectively. Stakeholders typically assumed a project operational life of 25 years.

7.2.1 Capital Expenditure

For ACT the most significant cost relates to the generation equipment, chambers and fuel processing equipment. For the average ('medium') Standard ACT project the construction cost is equal to around £6.2m/MW, for Advanced ACT it is £7.2m/MW and for ACT CHP £9.1m/MW. Infrastructure cost represent £0.12m/MW and £0.15m/MW for Standard and Advanced ACT respectively. Please note that for infrastructure cost Arup has estimated a combined arithmetic average cost which is used in all ACT LCM templates. Pre-development cost includes achieving planning permission, regulatory compliance and design. The costs averages £0.18m/MW for Standard ACT £0.41m/MW for Advanced ACT and £0.4m/MW for ACT CHP.

By combining the pre-development, construction and infrastructure costs gives a total capex estimate of £6.5m/MW, £7.8m/MW and £11.9m for ACT Standard, ACT Advanced and ACT CHP respectively.

During the 2011 Arup study infrastructure costs were not reported separately and were assumed to be included within total construction cost. For the 2015 Study data was collected at a greater level of detail than the Arup 2011 study, hence infrastructure and construction costs were separated.

Table 49 Capital Costs (financial close 2015), 2014 Real Prices £'000/MW

£'000/MW	Standard ACT	Advanced ACT	ACT CHP
Low	4,396	4,529	6,666
Medium	6,494	7,763	11,892
High	7,640	13,615	20,515

Table 50 Capital Cost Breakdown for a Medium Project %

Capital cost item	Standard ACT	Advanced ACT	ACT CHP
Pre-development	2.8%	5.2%	3.4%
Construction	95.3%	92.8%	76.5%
Infrastructure	1.8%	2.0%	20.0%

7.2.2 Capital Cost Learning Rate Assumption and Forecast

Stakeholders were asked to provide a view on what they considered to be the main cost drivers behind pre-development, construction and operations cost. Respondents also provided opinions on how they believed capex and opex costs are likely to change in the future. Based primarily on stakeholder feedback, but also using publically available literature, an Arup view on the future direction of cost was prepared and developed into a learning rate forecast (please see **Appendix E** for a summary of the methodology applied.). Respondents provided an opinion on how they believed capex and opex costs are likely to change in the future. For the forecast Arup primarily used stakeholders' survey responses to generate its forecast.

Arup's approach involved developing a forecast split by component civil works, fuel handling / preparation, balance of plant, converter and prime mover. Taking into account different learning rates linked to UK deployment of ACT.

From a construction cost perspective for both Standard and Advanced ACT the main drivers were reported to be exchange rates, availability of finance, labour and commodity prices (steel and copper) and chemicals. Stakeholders have also reported that they expect capex to continue to fall driven primarily by improved efficiency in project delivery and technical advances in the technology. The following provides the forecast Arup has produced.

Table 51 Advanced ACT Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	4,529	4,276	4,069	3,874
Medium	7,763	7,342	6,999	6,676
High	13,615	12,887	12,294	11,734

Table 52 Standard ACT Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	4,396	4,147	3,943	3,752
Medium	6,494	6,132	5,838	5,560
High	7,640	7,220	6,877	6,554

Table 53 ACT CHP Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	6,666	6,375	6,138	5,915
Medium	11,892	11,361	10,928	10,519
High	20,515	19,529	18,726	17,969

The ACT capital cost forecast is based on analysis of stakeholder views and external literature. Overall, the Standard ACT stakeholders provided a consistent view for future cost; Advanced ACT stakeholders only provided two viewpoints, one of which was assessed to be highly optimistic and the other expected the rate of change in cost to be the same as Standard ACT. It should be noted that there is a shortage of views and external reports on potential cost reduction. Therefore, taking into account the lack of data on the future direction of cost for Advanced

ACT, Arup has decided to adopt a conservative approach and assume the same cost reduction forecast across all types.

There is expected to be continued downward pressure on construction cost in the future. **Appendix C**, provides a summary of the cost index forecast applied. Based on an analysis of learning rates and deployment the reduction in cost is expected to be 5.8% by 2020, 10.6% by 2025 and 15.1% by 2030, which is equal to an annual reduction of -1.1%. The learning rates has been estimated based on data and view of stakeholders.

7.3 Operating Costs

Operating cost for ACT plants is primarily driven by the labour required to operate and maintain gas production and generation equipment. Operational costs show only a small range of +/- 2% above and below the medium cost for Standard ACT, however for Advanced ACT the range is quite large +/- 24% to 27% above and below the medium cost. The analysis indicates that operational requirements do not vary considerably for Standard ACT but for Advanced ACT there is a wider range of operating cost, implying that operating cost is still relatively uncertain.

Table 54 provides an indication of the variation in operating cost between the categories. Overall for the Advanced and Standard forms of ACT the cost ranges from £412k/MW to £698k/MW and £449k/MW to £468k/MW respectively. For both Advanced and Standard ACT average operating costs follow the expected trend i.e. Standard O&M is cheaper than Advanced. Cost is expected driven by project specific project conditions such as availability of equipment and skilled labour.

Table 54 Operating Costs (financial close 2015), 2014 Real Prices £'000/MW

£'000/MW	Standard ACT	Advanced ACT	ACT CHP
Low	449	412	412
Medium	459	548	548
High	468	698	698

7.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs stakeholders identified labour and availability of components as important cost drivers. Broadly stakeholders indicated that they expect operating costs to continue and fall driven primarily by learning effects, improvements in supply chain and better understanding of the project lifecycle.

For the opex learning rate forecast Arup relied on information provided by the stakeholders. Four categories of opex were considered which included fixed O&M and variable O&M, insurance and grid cost. For grid costs Arup used its own UoS (TNUoS and DNUoS trend) assumptions, for insurance this was linked to capex, fixed and variable opex were linked to the views reported by stakeholders.

Appendix C, provides a summary of the cost index forecast applied to Advanced, Standard and CHP forms of ACT. Based on an analysis of learning rates and deployment the reduction in opex cost is expected to be 2.8% by 2020, 5.5% by 2025 and 8.2% by 2030.

Table 55 Advanced ACT Operating Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	412	401	390	380
Medium	548	533	519	505
High	698	679	661	643

Table 56 Standard ACT Operating Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	449	437	426	415
Medium	459	446	435	423
High	468	455	443	432

Table 57 ACT CHP Operating Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	412	401	390	380
Medium	548	533	519	505
High	698	679	661	643

7.4 Gate Fee Estimates

Arup used stakeholder data to estimate low, medium and high gate fee. It should be noted that most of the data provided was in £/tonne, for modelling purposes Arup converted the £/tonne values into a £/MWh using a gross calorific value ('GCV') of 17.3GJ/tonne.

- From the data set collected it was observed that five data points were of the same high gate fee. The reason for this was that the five data points could be attributed to a specific technology developer, which has been successful at achieving high gate fees relative to the other developers. Consulting with stakeholders validated this initial viewpoint. Based on the stakeholder engagement Arup decided to remove the five high gate fees which were skewing the dataset.
- Through a process of stakeholder engagement Arup arrived at new set of representative market ACT gate fees. Table 58 provides the final ACT gate fee assumptions used for LCOE modelling and assumed constant for the forecast period. Due to a lack of reliable external stakeholder data and evidence on the future direction of gate fees Arup has made the assumption that gate fees remain fixed for the forecast period. It is not unreasonable to expect that ACT gate fees will continue to fall in the future. For example, in the AD sector gate fees have fallen as a result of deployment, increased competition and availability of plant. The likelihood that gate fees will fall is therefore dependent upon new ACT plants being developed and therefore the competition for fuel increasing.

Table 58 ACT Gate Fee Assumptions Forecast 2016 – 2030, 2014 Real Prices £/MWh[30]

£/MWh	2015	2020	2025	2030
Low	-13.53	-13.53	-13.53	-13.53
Medium	-12.14	-12.14	-12.14	-12.14
High	-10.40	-10.40	-10.40	-10.40

7.5 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare with existing DECC assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Tables 59 to 61 below provide current cost estimates for 2015, the DECC assumptions comparator and percentage change. It should be noted that the cost data collected is for ACT projects that have commenced operation or are under development.

New and old cost estimates for: pre-development, construction; infrastructure; and operating cost are presented below. The following provides Arup's view on what has caused the change in cost between DECC's cost assumptions and Arup's 2015 update:

- **Pre-development cost:** for both Advanced and Standard forms of ACT the key drivers behind the cost are similar. Challenges are reported to include technical design, planning and environmental permitting. Overall for Advanced ACT pre-development costs were estimated to be similar to those already assumed by DECC, for Standard costs are reported to have halved, reflecting an improved understanding of delivering ACT projects.
- **Construction cost:** a comparison of the DECC LCOE data to the Arup 2015 update indicated a small increase in construction cost for both Advanced and Standard forms of ACT. The stakeholder engagement process indicated that the key drivers behind the increase include technical challenges in deployment of the technology. Key drivers behind future changes in cost (reductions) are expected to be further deployment and standardisation of the technology.
- It should be noted that the technology is starting to exhibit NOAK characteristics. As projects continue to be deployed more certainty around the cost is likely to become available and lead to commercialisation.

[30] The value of the gate fees and GCV were based on five data points provided by ACT stakeholders.

- **Operating costs:** are understood to be driven by labour costs (which have remained relatively flat), the price of treatment chemicals e.g. lime carbon and the disposal of hazardous waste. Operating costs will vary depending on the type of fuel input into the ACT and the treatment process involved. The analysis indicated a small decrease in operational cost for Advanced ACT and a larger decrease in cost for Standard ACT when compared to DECC's current assumptions. Importantly, the data currently indicates that overall current opex costs have fallen from £658k/MW to £459k/MW, reflecting greater certainty with cost estimation. The change in cost is mainly driven by falls in fixed and variable O&M.
- It was concluded that there was no reliable benchmark data available for Standard, Advanced and CHP forms of ACT. Therefore, no external benchmark analysis was carried out.

Table 59 Advanced ACT Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	405	405	405	405
	Construction	£/kW	7,206	6,785	6,442	6,119
	Infrastructure	£'000	1,430	1,430	1,430	1,430
	Total capex	**£/kW**	**7,763**	**7,342**	**6,999**	**6,676**
	Total opex	**£MW**	**547,670**	**532,919**	**518,818**	**504,879**
	Fixed O&M	£/MW	158,647	154,156	149,862	145,618
	Variable O&M	£/MWh	38.2	37.1	36.1	35.1
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	83,812	81,439	79,171	76,929
	UoS	£/MW	12,774	12,774	12,774	12,774
DECC Current	Pre-development	£/kW	422	422	422	422
	Construction	£/kW	6,974	6,753	6,657	6,562
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**7,396**	**7,174**	**7,078**	**6,984**
	Total opex	**£/MW**	**556,422**	**531,034**	**506,817**	**483,718**
	Fixed O&M	£/MW	426,780	407,095	388,318	370,407
	Variable O&M	£/MWh	13.3	12.7	12.1	11.5
	Insurance	£/MW	22,516	21,477	20,487	19,542
	UoS	£/MW	6,008	6,008	6,008	6,008
	Pre-development	%	-4%	-4%	-4%	-4%

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	3%	0%	-3%	-7%
	Infrastructure	%	-	-	-	-
	Total capex	**%**	**5%**	**2%**	**-1%**	**-4%**
	Total opex	**%**	**-2%**	**0%**	**2%**	**4%**

Table 60 Standard ACT Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	183	183	183	183
	Construction	£/kW	6,191	5,830	5,535	5,257
	Infrastructure	£'000	1,430	1,430	1,430	1,430
	Total capex	**£/kW**	**6,494**	**6,132**	**5,838**	**5,560**
	Total opex	**£MW**	**458,558**	**446,330**	**434,640**	**423,085**
	Fixed O&M	£/MW	233,685	227,069	220,745	214,493
	Variable O&M	£/MWh	19.4	18.8	18.3	17.8
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	56,983	55,370	53,828	52,303
	UoS	£/MW	12,774	12,774	12,774	12,774
DECC Current	Pre-development	£/kW	373	373	373	373
	Construction	£/kW	5,763	5,580	5,501	5,438
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**6,136**	**5,953**	**5,874**	**5,811**

	Assumption	Unit	2015	2020	2025	2030
	Total opex	**£/MW**	**658,153**	**628,073**	**599,380**	**572,011**
	Fixed O&M	£/MW	438,038	417,834	398,561	380,178
	Variable O&M	£/MWh	24.6	23.4	22.3	21.3
	Insurance	£/MW	22,516	21,477	20,487	19,542
	UoS	£/MW	6,008	6,008	6,008	6,008
% Change	Pre-development	%	-51%	-51%	-51%	-51%
	Construction	%	7%	4%	1%	-3%
	Infrastructure	%	-	-	-	-
	Total capex	%	**6%**	**3%**	**-1%**	**-4%**
	Total opex	%	**-30%**	**-29%**	**-27%**	**-26%**

Table 61 ACT CHP Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	405	405	405	405
	Construction	£/kW	9,103	8,572	8,139	7,730
	Infrastructure	£'000	1,430	1,430	1,430	1,430
	Total capex	**£/kW**	**11,892**	**11,361**	**10,928**	**10,519**
	Total opex	**£MW**	**547,670**	**532,919**	**518,818**	**504,879**
	Fixed O&M	£/MW	158,647	154,156	149,862	145,618
	Variable O&M	£/MWh	38.2	37.1	36.1	35.1
	BSUoS	£/MWh	1.9	1.9	1.9	1.9

	Assumption	Unit	2015	2020	2025	2030
	Insurance	£MW	83,812	81,439	79,171	76,929
	UoS	£/MW	12,774	12,774	12,774	12,774
DECC Current	Pre-development	£/kW	89	89	89	89
	Construction	£/kW	6,006	5,815	5,732	5,651
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**6,095**	**5,904**	**5,821**	**5,740**
	Total opex	**£/MW**	**633,169**	**604,242**	**576,648**	**550,328**
	Fixed O&M	£/MW	438,038	417,834	398,561	380,178
	Variable O&M	£/MWh	24.6	23.4	22.3	21.3
	Insurance	£/MW	22,516	21,477	20,487	19,542
	UoS	£/MW	6,008	6,008	6,008	6,008
% Change	Pre-development	%	355%	355%	355%	355%
	Construction	%	52%	47%	42%	37%
	Infrastructure	%	-	-	-	-
	Total capex	%	**95%**	**92%**	**88%**	**83%**
	Total opex	%	**-14%**	**-12%**	**-10%**	**-8%**

7.6 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC's current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net Power:** the overall scale of the average plant is reported to have reduced in from 15MW to 9MW for Advanced and 15MW to 12MW for Standard ACT. The change in scale reflects an increase in certainty from developers on the scale of current and planned plants when compared to existing DECC assumptions.

- Steam output was also noted as decreasing significantly between DECC's current and Arup's 2015 updated figure, 12.6MWth to 0.3MWth.
- **LHV efficiency:** compared to the existing DECC assumptions stakeholders have reported a marginal decrease in LHV efficiency of 5% and 2% decrease for Standard and Advanced ACTs respectively.
- **Availability:** Arup reviewed and interpreted the availability data provided by stakeholders and assessed it to represent the maximum time proportion a plant will be available to generate in a year after downtime for maintenance work. For the purposes of the analysis it was assumed that availability is the same as 'net load factor' defined under Section Three.
- **Load factor:** the current figure of 83.2% falls within Arup's expected load factor range of 80% - 85% for ACT projects. Importantly, stakeholders have reported a marginal decrease in load factor which is expected to have a small increase on LCOE. A summary of the load factors used for the analysis is provided in **Appendix B.**

Table 62 Advanced ACT Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	15.00	9.44	-5.56
Net LHV efficiency	%	25.8%	25.3%	-1.8%
Availability	%	86.8%	100.0%	15.3%
Load factor (gross)	%	100.0%	83.2%	-16.8%
Load factor (net)	%	86.8%	83.2%	-4.1%

Table 63 Standard ACT Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	15.00	11.94	-3.06
Net LHV efficiency	%	22.1%	20.9%	-5.4%
Availability	%	89.0%	100.0%	12.3%
Load factor (gross)	%	100.0%	83.2%	-16.8%
Load factor (net)	%	89.0%	83.2%	-6.5%

Table 64 ACT CHP Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	15.00	0.60	-14.40
Average steam output	MWth	12.63	0.31	-12.32
Net LHV efficiency	%	19%	24%	25.8%
Availability	%	89%	100%	12.4%
Load factor (gross)	%	87%	83%	-4.3%
Load factor (net)	%	77%	83%	7.5%

The assumed load factors for are presented below on Table 65 and the assumed installation lifetime is 25 years. Please note that the data received from stakeholders was assumed to be net of availability. The technical assumptions tables 62 to 64 above include indicate availability of 100%, assumed for LCOE modelling only.

Table 65 Assumed Load Factor %

%	Standard ACT	Advanced ACT	ACT CHP
Medium, gross	83.2%	83.2%	83.2%
Medium, net	83.2%	83.2%	83.2%

No reliable data points were available from the literature review for load factor. We therefore used stakeholder data for the minimum, average and maximum for 2015. No data was available from stakeholders indicating how load factor could be expected to change in the future.

7.7 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for the ACT reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Tables 69 to 71 provide the LCOE results based on DECC's updated hurdle rate for the technology.

Table 66 Advanced ACT LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	96	98	92	87
Medium	149	150	142	135
High	243	246	233	222

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 67 Standard ACT LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	58	59	54	50
Medium	84	86	80	74
High	99	100	94	88

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 68 ACT CHP LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	102	104	96	90
Medium	178	180	169	160
High	302	306	289	275

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 69 LCOE 2016 – 2030 (ACT Standard), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	66	67	62	57
Medium	96	98	91	85
High	113	115	107	101

Table 70 LCOE 2016 – 2030 (ACT Advanced), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	95	97	91	86
Medium	147	148	140	133
High	239	242	229	218

Table 71 LCOE 2016 – 2030 (ACT CHP), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	119	121	112	105
Medium	208	211	198	188
High	354	359	339	323

7.8 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup's new cost data, DECC's current assumptions and discount rates. A summary of all the LCOEs generated using DECC's current and new hurdle rates are presented in **Appendix I.**

For both Advanced and Standard forms of ACT there has been a very small increase in construction cost which has been offset by a small reduction in operating cost for Advanced ACT but a large (30%) reduction for Standard ACT plant. The fall in operating costs reflect improvements within the supply chain for O&M services, operator learning effects allowing optimisation of the project lifecycle.

It should be noted that when the estimated construction cost is compared with the external benchmarks from (BNEF, Global Gasification Scenario) there is a large difference when compared to Arup's central figure (£2,923/MW vs. £6,191/MW). Although there is a significant difference Arup is confident with the construction cost figure it has estimated, based on its experience and engagement during the consultation process.

Overall, for Advanced and Standard forms of ACT the data indicates that a project commissioning by 2020 will have an LCOE which is 9%, 34% less than current

DECC figures. For ACT CHP LCOE is expected to be 28% higher than current DECC estimates.

For comparison purposes the current DECC figures have been inflated from 2012 to 2014 prices. Key cost and technical drivers for ACT advanced are an increase in capital cost and a marginal decrease in operating cost. For ACT Standard, there is expected to be a small increase in construction cost and a fall in operating costs.

Table 72 ACT Advanced Comparison Arup vs. DECC, 2014 Real Prices £/MWh

£/MWh	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	96	98	133	133	-27.3%	-26.4%
Medium	149	150	165	165	-9.7%	-8.6%
High	243	246	178	178	36.3%	37.8%

Table 73 ACT Standard Comparison Arup vs. DECC, 2014 Real Prices £/MWh

£/MWh	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	58	59	70	70	-17.1%	-15.6%
Medium	84	86	130	130	-35.3%	-34.3%
High	99	100	195	195	-49.5%	-48.7%

Table 74 ACT CHP Comparison Arup vs. DECC, 2014 Real Prices £/MWh

£/MWh	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	102	104	62	62	65.6%	68.4%
Medium	178	180	141	141	26.3%	28.0%
High	302	306	218	218	38.5%	40.3%

8 Biomass CHP

8.1 Introduction

Biomass CHP is the simultaneous generation of electricity and heat from biomass The heat produced as a co-product of the CHP is typically used for space heating, hot water and steam for industrial processes. Biomass CHP is generally located at sites that demand both heat and electricity.

Since 2010 Biomass CHP development has increased steadily. New schemes are typically designed to serve reliable heat demands with a supply of process heat or steam. Plant locations include distilleries, refineries and industrial parks.

Relative to other renewable technologies Biomass CHP is one of the more ‘proven’ thermal technologies. There is a range of technology providers and developers now established in the market, demonstrating their ability to deliver projects.

No significant new innovations are expected given that the technology is now an established and extensively researched technology. Key challenges for the technology include better use of the heat generated, improvements in efficiency of plant, locating suitable sites for projects and purchasing sufficient quantities of sustainable feedstock.

For the analysis the generation cost information was supplied via stakeholders, published reports and internal sources. For the Arup 2011 study DECC had requested that the data was collated for biomass CHP only. For this 2015 Study, Arup again only collected data for one category, with CHP operating in two modes (condensing and CHP-mode), reporting cost in ‘full condensing’ (i.e. no heat) and ‘CHP-mode’. Cost and technical variables were reported as follows:

- Biomass CHP, full condensing;
- Biomass CHP, CHP-mode.

CHP can be operated in two modes which; condensing and CHP-mode. The primary type used for electricity generation is the condensing form and involves a vacuum process, which maximises power and electrical generation efficiency from steam supply and boiler fuel. Plants operating in CHP-mode typically exhaust steam to an industrial process or a facility steam mains. Electricity generation reduces when steam is used in a process rather than expanded to vacuum in a condenser.

It should be noted that there were limited number of responses received via the stakeholder engagement process. Where there was a shortage of data Arup has used alternative published sources for benchmarking and analysis. Based on the data received stakeholders typically assumed that the typical operational life of a biomass CHP is 24 years.

To support the analysis Arup engaged with Ricardo-AEA to understand the average and ‘typical’ scale of plant being deployed in the UK. The data provided to Arup by Ricardo-AEA was assessed to more representative than the data collected through the stakeholder engagement process.

8.2 Data Collection

Data was collected from stakeholder, internal and published sources. For the data collection process Arup contacted manufacturers, developers, trade associations and utility companies. Overall, data was collected from internal projects and 2 developers, initially yielding 7 project data points.

Based on the data collection criteria outlined in Chapter Three, 5 data points were assessed to be robust, representative and useful to the analysis. All results produced during the analysis were compared with the original stakeholder data and collated benchmarks.

In terms of installed capacity the 7 data points represented capacity of 103MW of projects at various stages of development (operational, under construction and planned). Post evaluation the final 5 data points (five stakeholder) were used for the analysis with a total estimated capacity of 93MW. The average plant size for the data points was estimated to be 19MW. The data collection included projects between 6.5MW and 35MW of installed capacity.

8.2.1 Capital Expenditure

Pre-development costs have been reported to vary significantly between £0.03m/MW to £0.49m/MW shared equally between pre-licensing, planning and technical development. Obtaining planning consent was expected to be highly variable between projects. The collated data indicated pre-development costs varied widely and are quite site specific and not necessarily related to the overall scale of a project.

Variations in capital costs between projects and were reported to be driven by three key factors including feedstock type, process configuration and economies of scale. For all forms of biomass CHP the most significant capital costs relate to the generation equipment and fuel processing equipment. For the medium project the capital cost is equal to around £3.71m/MW. Other costs such as grid infrastructure represent around an additional £0.05m/MW. By combining the pre-development, construction and infrastructure costs total capital costs were estimated to be £3.99m/MW (condensing cost). Table 76 provides total capital cost on a CHP-mode basis. Please see Chapter Three for the methodology applied to generate the estimates.

Table 75 Biomass CHP Capital Costs (2015 Financial Close), 2014 Real Prices, Full Condensing Basis £'000/MW

£'000/MW	Biomass CHP
Low	2,864
Medium	3,985
High	4,976

Table 76 Biomass CHP Capital Costs (2015 Financial Close), 2014 Real Prices CHP-mode £'000/MW

£'000/MW	Biomass CHP
Low	3,406
Medium	4,739
High	5,916

Table 77 Biomass CHP Capital Cost Breakdown for a Medium Project, Full Condensing %

Capital cost item	Biomass CHP
Pre-development	5.6%
Construction	93.2%
Infrastructure	1.2%

Table 78 Biomass CHP Capital Cost Breakdown for a Medium Project, CHP-mode %

Capital cost item	Biomass CHP
Pre-development	5.6%
Construction	93.0%
Infrastructure	1.4%

8.2.2 Capital Cost Learning Rate Assumption and Forecast

Stakeholders were asked to provide a view on what they considered to be the main cost drivers behind pre-development, construction and operations cost. Based on stakeholder feedback and publically available literature an Arup view on the future direction of cost was prepared and developed into a learning rate forecast. All respondents provided an opinion on how they expected cost to change in the future. Arup primarily used stakeholder survey responses combined with a learning rate forecast produced by the IEA to generate a construction costs trajectory.

From a construction cost perspective the main cost drivers are reported to be exchange rates, availability of finance, labour and commodity prices. Stakeholders have reported that they expect capex to rise slightly over the long-run. Table 79 and 80 provide the capital cost forecast Arup has produced based on the forecast cost trajectory.

Based on external data provided via stakeholders and external publications Arup was able to form a view on the future direction of construction cost. Overall, there is expected to be an increase in construction cost. **Appendix C**, provides a summary of the cost index forecast which has been applied to biomass CHP. Based on an analysis of learning rates and deployment the increase in cost is expected to be 10.0% by 2020, 11.5% by 2025 and 10.4% by 2030.

Table 79 Biomass CHP Capital Cost Forecast 2015 – 2030, 2014 Real Prices Full Condensing Basis £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	2,864	3,144	3,186	3,155
Medium	3,985	4,357	4,414	4,372
High	4,976	5,419	5,487	5,437

Table 80 Biomass CHP Capital Cost Forecast 2015 – 2030, 2014 Real Prices CHP-mode £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	3,406	3,738	3,788	3,751
Medium	4,739	5,180	5,248	5,198
High	5,916	6,442	6,523	6,463

8.3 Operating Cost

Operating cost for biomass CHP plants are driven by the labour required to operate and maintain production and generation equipment. Operational costs show a large range reflecting the operational requirements of each project in the Arup dataset. The wide variance in cost implies that the cost for operating this type of plant is still relatively uncertain and to a degree site specific. O&M services are typically supplied by equipment manufacturers.

Tables 81 to 82 below provide an indication of the variation in operating cost between the categories. Overall for CHP the cost ranges from £195k/MW to £488k/MW, average operating cost is around £299k/MW. Operating cost is expected to be mainly driven by project specific conditions, availability of equipment and skilled labour.

8.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs stakeholders identified labour and availability of components as an important cost drivers. In addition, Arup is also aware that emission abatement is also an important component of biomass CHP operations. Broadly stakeholders indicated that they expect operating costs to continue to increase as a result of constraints around the biomass supply chain and its ability to provide the required equipment.

Appendix C, provides a summary of the cost index forecast applied to biomass CHP. Based on an analysis of learning rates and deployment, opex cost is expected to increase by 7.6% by 2020, 9.2% by 2025 and 9.1% by 2030.

Table 81 Biomass CHP Operating Costs (Financial Close 2015), 2014 Real Prices Full Condensing Basis £'000/MW

£'000s/MW	Biomass CHP
Low	195
Medium	299
High	488

Table 82 Biomass CHP Operating Costs (Financial Close 2015), 2014 Real Prices CHP-mode £'000/MW

£'000s/MW	Biomass CHP
Low	234
Medium	352
High	577

For the opex learning rate forecast Arup combined the existing DECC's opex forecast along with information provided by the stakeholders. Four categories of opex were considered which included fixed and variable O&M, insurance and grid costs. For grid costs Arup used its own UoS (TNUoS, BSUoS and DNUoS trend) assumptions, for insurance this was linked to capex, fixed and variable opex were linked to the views reported by stakeholders.

Table 83 and 84 provides Arup's forecast for the future operating costs of each type of plant.

Table 83 Biomass CHP Operating Cost Forecast 2016 – 2030, 2014 Real Prices Full Condensing Basis £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	195	208	211	211
Medium	299	319	324	324
High	488	523	530	529

Table 84 Biomass CHP Operating Cost Forecast 2016 – 2030, 2014 Real Prices CHP-mode £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	234	250	253	253
Medium	352	377	382	381
High	577	617	626	625

8.4 Biomass Fuel Prices

Arup has collated and reviewed biomass fuel price data from five stakeholders and four internal benchmarks. The stakeholder data indicated that the typical fuel input used in biomass CHP is waste wood. The use of waste wood as the 'typical' fuel type conformed to Arup's expectations and has therefore been assumed for LCOE modelling purposes.

The following has been assumed to generate a £/MWh value:

- A GCV[31] of 12.5 GJ/tonne[32].
- To convert from GJ to MWh a conversion of 3.6 is applied.

Arup collected nine data points from internal and external stakeholder sources. Eight data points represented waste wood fuel contracts and one a wood chip and distillery mix. The fuel input data was assessed to be representative following an internal and external review. Waste wood fuel was therefore assumed to be the typical fuel used in biomass CHP.

[31] Energy content of the fuel is presented in Gross Calorific Value ('GCV') terms.

[32] It should be noted that Whitaker and Murphy (2009) provide an average moisture content for all biomass waste of 29%, which would have an energy content of 12.5GJ/tonne.

Arup has been able to estimate a low, medium and high biomass price presented on table 85 below. The medium value of £9.66/MWh can be compared to DECC's current assumption of £22.63/MWh. The large fall in waste wood fuel prices can be attributed to improvements in UK biomass supply chain, availability of waste wood fuel and competition within the biomass supply sector.

Table 85 Biomass CHP Biomass Fuel Price Assumptions Forecast 2015 – 2030, 2014 Real Prices[33]£/MWh

£/MWh	2015	2020	2025	2030
Low	3.55	3.55	3.55	3.55
Medium	9.66	9.66	9.66	9.66
High	31.20	31.20	31.20	31.20

8.5 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these with DECC's existing assumptions. The objective of the analysis was to identify where costs had changed and understand what is driving these changes in cost. Table 86 provides current cost estimates for 2015, the DECC assumptions comparator and percentage change.

It should be noted that the number of data points captured for the analysis is relatively small. Therefore, a comparison between existing DECC assumptions and the Arup 2015 figures is difficult. The cost data received has been validated internally.

It should be noted that the cost data collected is for biomass CHP plants that have reached final commissioning or were under development at the time of the stakeholder survey. For the comparison Arup has used DECC's current cost estimates and compared these with those generated by this Study. New and old cost estimates for: pre-development; construction; infrastructure; and operating cost are presented below along with Arup's view of what has caused the change:

- **Pre-development cost:** no pre-development cost data were available for comparison with the Arup 2015 figures. Therefore Arup validated the cost data internally.
- **Construction cost:** a comparison of the DECC assumptions and the Arup 2015 update indicates a small overall decrease in construction cost of around -

[33] Please note that all biomass fuel price assumptions presented in the report are in £/MWh values.

-5%. Biomass CHP is a relatively well known technology with costs not expected to have changed significantly. This was also reflected via an internal comparison of tender returns from potential EPC contractors, indicating only a small variance between EPC supplier costs. Based on the available data and our knowledge that biomass CHP costs are relatively well know it is Arup's view that there is little scope for additional cost reduction.

- **Operating cost:** cost is understood to be driven by labour costs required to operate and maintain the plant and the disposal of waste. A wide range in cost was observed reflecting the operational requirements of each project in the Arup dataset, reflecting that the cost of operating this type of plant is still relatively uncertain. Overall operating cost is reported to have increased by around **20%** (biomass CHP condensing).
- It should be noted that capex and opex will vary depending on the type of fuel input into the biomass CHP. For example, waste wood typically has a higher handling cost than wood pellets since a testing and cleaning process will need to be in place.
- UoS costs are noted as being high relative to existing DECC assumptions. The current UoS cost estimates are based on real projects which provided confidence in the figures being used for the analysis. It should be noted that the dataset collected is quite small and could be causing the overall increase in cost.

Table 86 Biomass CHP Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices Full Condensing Basis

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	223	223	223	223
	Construction	£/kW	3,714	4,086	4,143	4,101
	Infrastructure	£'000	774	774	774	774
	Total capex	**£/kW**	**3,985**	**4,357**	**4,414**	**4,372**
	Total opex	**£MW**	**298,836**	**319,482**	**323,819**	**323,522**
	Fixed O&M	£/MW	185,700	199,767	202,722	202,520
	Variable O&M	£/MWh	7.1	7.7	7.8	7.8
	BSUoS	£/MWh	1.9	1.9	1.9	1.9

	Assumption	Unit	2015	2020	2025	2030
	Insurance	£MW	36,569	39,339	39,921	39,881
	UoS	£/MW	12,921	12,921	12,921	12,921
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	3,907	3,828	3,791	3,755
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**3,907**	**3,828**	**3,791**	**3,755**
	Total opex	**£/MW**	**253,943**	**249,011**	**246,871**	**244,749**
	Fixed O&M	£/MW	154,030	151,022	149,716	148,421
	Variable O&M	£/MWh	9.9	9.7	9.6	9.6
	Insurance	£/MW	26,107	25,597	25,376	25,156
	UoS	£/MW	1,458	1,458	1,458	1,458
% Change	Pre-development	%	-	-	-	-
	Construction	%	-5%	7%	9%	9%
	Infrastructure	%	-	-	-	-
	Total capex	%	**2%**	**14%**	**16%**	**16%**
	Total opex	%	**18%**	**28%**	**31%**	**32%**

Table 87 Biomass CHP Cost Comparison between Arup 2015 and DECC Current, 2014 Prices CHP-mode

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	265	265	265	265
	Construction	£/kW	4,406	4,848	4,915	4,865
	Infrastructure	£'000	918	918	918	918
	Total capex	**£/kW**	**4,739**	**5,180**	**5,248**	**5,198**
	Total opex	**£MW**	**352,056**	**376,551**	**381,697**	**381,345**
	Fixed O&M	£/MW	220,321	237,011	240,517	240,277
	Variable O&M	£/MWh	8.5	9.1	9.3	9.2
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	43,387	46,673	47,364	47,317
	UoS	£/MW	15,330	15,330	15,330	15,330
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	3,907	3,828	3,791	3,755
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**3,907**	**3,828**	**3,791**	**3,755**
	Total opex	**£/MW**	**253,943**	**249,011**	**246,871**	**244,749**
	Fixed O&M	£/MW	154,030	151,022	149,716	148,421
	Variable O&M	£/MWh	9.9	9.7	9.6	9.6
	Insurance	£/MW	26,107	25,597	25,376	25,156
	UoS	£/MW	1,458	1,458	1,458	1,458
% Change	Pre-development	%	-	-	-	-

	Assumption	Unit	2015	2020	2025	2030
	Construction	%	13%	27%	30%	30%
	Infrastructure	%	-	-	-	-
	Total capex	%	**21%**	**35%**	**38%**	**38%**
	Total opex	%	**39%**	**51%**	**55%**	**56%**

Arup reviewed the estimates it produced against benchmark costs from other renewable market reports and publications. The objective here was to provide a validation of the findings and provide comfort around the observations. To understand the change in cost Arup analysed different development, construction and opex benchmark data for Biomass CHP. Overall, the following was observed when compared to the Arup 2015 figures:

- **Construction costs:** comparator data was available from the IEA which estimated the cost to be £2,650/kW. The 2015 estimate of £3,714/kW is higher however Arup understand that the current benchmark from the IEA is an international figure and is not necessarily representative of UK specific costs. Importantly the construction cost data generated by the Study did reflect the expected trend in cost reduction.
- No comparator data was available for pre-development and operating costs.

8.6 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC's current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net Power:** based on the data provided by stakeholders the average installed capacity was initially estimated to be 19.5MW. When compared to DECC's current assumption there has been a large reduction from 62.0MW. It is understood that stakeholders are currently focussed on developing sites that are smaller than previously assumed and expected, located at industrial sites. Arup was aware of the small number of data points it used to estimate average installed capacity. Arup contacted Ricardo-AEA which provided additional data on the average scale of plant registered via CHPQA. Based on 17 data points the average plant capacity was estimated to be 16MW (17.9MW gross). It was therefore concluded that the data provided by Ricardo-AEA was more representative in terms of the average scale of plant being delivered in the UK.
- Steam output was also observed to have decreased significantly between DECC's current and Arup's 2015 estimate (139.5MWth to 14.5MWth). The change did conform with Arup's expectations and reflects current market

conditions. Arup understand that it is currently more economic to produce electricity than heat or steam.

- **LHV efficiency:** the stakeholder figures were validated internally and reviewed with DECC. Importantly, stakeholders have reported an overall improvement in efficiency. It is expected to be the result of operators running plant more efficiently and a small amount of technical improvement. Arup was aware of the limited number of data points used for analysis, therefore discussions with Ricardo-AEA were held to collate additional data on average condensing and CHP-mode efficiency. Arup understand that the data provided is based on 17 data points from the CHPQA register. The data was assessed to be representative of average operational plant efficiency.
- **Availability:** plant availability data was reported by stakeholders but no load factor information provided. Arup reviewed and interpreted the availability data as equivalent to the net load factor i.e. the maximum time proportion a plant will generate in a year. For the purposes of the analysis it was assumed that availability is the same as 'load factor', defined under Section Three. For modelling purposes only availability was set at 100%.
- **Load factors:** the load factor was observed to have decreased marginally by around 3.5% when compared on a net basis. The current figure of 80.3% appears to be within the range we would typically expect of 80% to 85%. A summary of the load factors used for the analysis is provided in Appendix B.

Table 88 Biomass CHP Technical Assumptions Full Condensing

Assumption	Unit	DECC	Arup	Change
Net Power	MW	62.00	16.11	-45.89
Average steam output	MWth	139.50	14.47	-125.03
Net LHV efficiency	%	20.0%	27.7%	38.4%
Availability	%	90.0%	100.0%	11.1%
Load factor (gross)	%	92.5%	80.3%	-13.1%
Load factor (net)	%	83.3%	80.3%	-3.5%

Table 89 Biomass CHP Technical Assumptions CHP-mode

Assumption	Unit	DECC	Arup	Change
Net Power	MW	62.00	13.58	-48.42
Average steam output	MWth	139.50	14.47	-125.03
Net LHV efficiency	%	20%	23%	16.6%
Availability	%	90%	100%	11.1%
Load factor (gross)	%	93%	80%	-13.1%
Load factor (net)	%	83%	80%	-3.5%

The assumed load factors for biomass CHP are presented below on table 90 and has an assumed technical lifetime is 24 years.

Table 90 Assumed Load Factor %

%	Biomass CHP
Medium, gross	80.3%
Medium, net	80.3%

The IEA provides an important and reliable secondary source of data. It indicates that the load factor will typically range from 76% to 91%. The load factor assumed for LCOE modelling is based on stakeholder data for the minimum, average and maximum for 2015. For the forecast period it held constant with no change due to limited information surrounding expected technological change. The load factor used for the LCOE analysis are close to those produced by the IEA.

8.7 Levelised Cost

Based on the learning rate forecast applied to capital and operating cost, new cost profiles were estimated. Arup calculated LCOE for the biomass CHP reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Tables 93 to 94 provide the LCOE results based on DECC's updated hurdle rate for the technology.

Table 91 Biomass CHP LCOE 2016 – 2030, 2014 Real Prices Full Condensing* £/MWh

£/MWh	2016	2020	2025	2030
Low	146	144	150	149
Medium	173	171	177	177
High	197	195	203	202

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 92 Biomass CHP LCOE 2016 – 2030, 2014 Real Prices CHP-mode* £/MWh

£/MWh	2016	2020	2025	2030
Low	140	139	141	139
Medium	172	171	174	171
High	201	199	204	201

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 93 LCOE 2016 – 2030 (Biomass CHP condensing*), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	141	139	144	144
Medium	165	163	170	169
High	188	185	193	192

** Assumed 17MWe*

Table 94 LCOE 2016 – 2030 (Biomass CHP CHP-mode), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	134	133	135	132
Medium	163	162	165	162
High	190	188	192	189

** Assumed 17MWe*

8.8 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup's new cost data, DECC's current assumptions for biomass CHP mode, and hurdle rates. A summary of all the LCOE generated using DECC's current and new hurdle rates is presented in **Appendix I.**

For biomass CHP operating in CHP-mode the data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE of around 16% and 17% less than current DECC figures[34]. Please note that DECC's current LCOE figures are for biomass CHP operating in CHP-mode, no direct comparator with the condensing mode CHP figures can be made. Key cost and technical drivers include a small fall in capital cost an increase in operating cost and a reduction in biomass CHP fuel prices. For comparison purposes the current DECC figures have been inflated from 2012 to 2014 prices.

[34] Future LCOE results will be highly sensitive to changes in fuel prices and the overall scale of demand for biomass.

Table 95 Biomass CHP Comparison Arup vs. DECC, 2014 Real Prices CHP-mode £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	140	139	179	181	-21.8%	-22.9%
Medium	172	171	204	206	-15.7%	-17.0%
High	201	199	229	231	-12.2%	-13.7%

9 Biomass Conversion

9.1 Introduction

Since the Arup 2011 study a series of coal plants in the UK have been redesigned to handle and burn biomass fuels. The main driver for large-scale conversion has been EU air quality and carbon targets, restricting the number of hours a coal fired power station can be operated for. Future operations are dependent upon the Large Combustion Plant Directive ('LCPD') and the Industrial Emissions Directive ('IED') which applies from January 2016.

The economics of converting coal plant to run biomass is dependent upon a number of factors including: current operational status; access to biomass sustainable supply; and the cost of fuel handling equipment. Biomass conversion projects contribute significantly to the UK's renewable energy targets. In the UK Drax is the largest consumer of biomass with the majority imported. Another plant expected to convert is Lynemouth (420MW) which has recently secured a capacity contract Ironbridge and Tilbury have now closed permanently, whilst Drax is expected to be continue and convert its remaining units[35].Drax has converted two of its six units to use 100% wood pellets. Drax is expected to convert a third unit by 2019.

For consistency with the 2011 Arup report conversion costs were assumed to represent the expenditure required to convert an existing coal fired station into a dedicated biomass plant. The data collected for the analysis is based upon consultation with stakeholders, relating to current projects under development and internal benchmark data.

The 2011 Arup report estimated generation cost and technical performance for projects with an installed capacity of between 100MW to 1,500MW. Arup has been able to collect marginally more data for the 2015 analysis, however the analysis was only presented for one category rather than splitting into the same categories as previous:

- Biomass conversion.

In addition, information was collected from publically available industry reports, stakeholders, equipment manufacturers and utility companies. The stakeholder data indicated that the expected technical life is around 15 years.

9.2 Data Collection

Data was collected from public, internal and stakeholder sources. The majority of the data used for the analysis was collected via internal and published sources yielding six data points (UK and international based projects). Although the total number of project data points was small, it was deemed to be reflective of the limited number of future conversion projects taking place in the UK. In addition

[35] The third unit is expected to be converted in 2015/16. Please see: www.drax.com/biomass/our-biomass-plans

Arup understand that all coal plants which are currently economic to convert are known.

Based on the data collection criteria outlined in Section 2, four data points were assessed to be robust, representative and useful to the analysis. All results produced during the analysis were compared with the original stakeholder data and collated benchmarks.

In terms of installed capacity the initial six data points represented capacity of 2,115MW of projects at various stages of development (operational, under construction and planned). Post evaluation the final four data points used for the analysis had a total estimated capacity of 1,412MW. The average plant size for the data points was estimated to be 353MW.

9.3 Capital Expenditure

The vast majority of capital expenditure is related to construction costs which include boiler replacement, construction of biomass storage facilities and modifications to material handling systems. Further work is also potentially required around local infrastructure such as rail network upgrades and port infrastructure improvements. For the analysis it has been assumed that the plants will already have an electrical connection in place.

Pre-development cost vary from £0.05m/MW to £0.12m/MW and includes pre-licensing costs, technical design (very bespoke to the specific plant) development costs, regulatory and environmental compliance reporting. Conversion construction costs are bespoke to the actual plant undergoing a conversion, costs vary between £0.20m/MW to £0.26m/MW with a mean cost of £0.24m/MW significantly lower than the current benchmark of £0.35m/MW produced by Poyry[36]. It is assumed that there are no new electrical infrastructure and connection costs associated with a conversion project.

Table 96 Biomass Conversion Capital Costs (2015 Financial Close), 2014 Real Prices £'000/MW

£'000/MW	Conversion
Low	245
Medium	321
High	378

[36] Technology Supply Curves for Low Carbon Power Station, Poyry, June 2013.
The current range of cost for conversion reported by Poyry is £0.25m/MW-£0.45m/MW, with Arup estimated mean cost is £0.35m/MW

Table 97 Biomass Conversion Capital Cost Breakdown for a Medium Project %

£'000/MW	Conversion
Pre-development	26.2%
Construction	73.8%
Infrastructure	0.0%

9.3.1 Capital Cost Learning Rate Assumption and Forecast

Based on external data provided via stakeholders, external reports and an internal review Arup was able to form a view on the future direction of construction cost. It was concluded that capital costs are unlikely to change, with no additional downward pressure and the majority of industry learning already taken place. Capital cost is therefore expected to be remain flat going forward. **Appendix C**, provides a summary of the cost index forecast which has been applied.

Table 98 Biomass Conversion Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	245	245	245	245
Medium	321	321	`321	321
High	378	378	378	378

The medium cost value is around half the previous value reported during the 2011 Arup study when compared to DECC's existing cost assumptions. Reasons for the change could include positive learning by doing effects, for example since the 2011 Arup study three large-scale conversion projects have been delivered, which is expected to have caused some of the costs decrease. However as discussed before the capital costs of delivering conversion is highly bespoke to the plant, combined with the knowledge that the majority of economic conversions have taken place.

9.4 Operating Cost

Operating costs for biomass conversion projects comprise mainly of fixed and variable O&M contracts, UoS charges, insurance and labour. Labour cost as part of O&M contracts is understood to be the main driver of plant operating cost. It is understood stakeholders have significant experience in operating plants and do not anticipate significant learning effects. The following provide the current range of operational costs and how these can be expected to change over time to 2020, 2025 and 2030. Table 99 below provides an indication of the variation in operating cost between categories. Overall for the UK the cost ranges from £46k/MWa to £63/MWa.

9.4.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs the literature and stakeholder engagement reviewed and identified labour and availability of components as important cost drivers. Stakeholders indicated that cost is expected to remain broadly flat going forward.

Appendix C, provides a summary of the cost index forecast applied to biomass CHP. Based on an analysis of learning rates and deployment opex cost is expected to remain stable at its current level.

Table 99 Biomass Conversion Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MWa	Conversion
Low	46
Medium	54
High	63

Table 100 Biomass Conversion Operating Cost Forecast 2016 – 2030, 2014 Real £'000/MW

£'000s/MWa	2015	2020	2025	2030
Low	46	46	46	46
Medium	54	54	54	54
High	63	63	63	63

9.5 Biomass Fuel Prices

Arup has collated and reviewed biomass fuel price data from stakeholder and benchmark sources and the European Commission[37]. The stakeholder data indicated that the typical fuel input used in biomass conversion is imported wood pellets. The use of wood pellets conformed to Arup's expectation and work within the industry.

The following has been assumed to generate a £/MWh value for the LCOE model:

- A GCV of 17 GJ/tonne[38];
- To convert from GJ to MWh a conversion of 3.6 is applied.

Arup has been able to estimate a minimum, average and maximum biomass price presented on table 101 below. The medium value of 28.96/MWh can be compared to DECC's assumption of £29.18/MWh. The data indicated that there has been only a marginal fall in wood pellet prices. The change in price is attributed to improvements in the UK biomass supply chain, investment in wood pellet handling facilities (ports, rail) and an increase in availability of wood pellets.

Table 101 provides a summary of the estimated biomass prices paid for by conversion plant operators. It should be noted that conversion plant will typically use a fuel that has a high energy and low moisture content relative to other forms of biomass generation. For example, dedicated biomass and biomass CHP were assessed to typically use waste wood as the main source of fuel, as opposed to more expensive forms of wood pellets.

Biomass fuel prices are assumed to remain constant over the forecast period. It is Arup's expectation that conversion developers will typically enter into a long-term fuel supply contracts that are typically 5 to 10 years in duration. In addition, no external views were provided by stakeholders.

Table 101 Biomass Conversion Biomass Fuel Price Assumptions Forecast 2015 – 2030, 2014 Real Prices £/MWh

£/MWh	2015	2020	2025	2030
Low	26.24	26.24	26.24	26.24
Medium	28.96	28.96	28.96	28.96
High	36.76	36.76	36.76	36.76

[37] http://ec.europa.eu/competition/state_aid/cases/255986/255986_1634646_59_2.pdf
[38] Biomass fuel prices and GCV are based on three data points provided via stakeholders and internal sources.

9.6 Cost Breakdown

Based on the collected data Arup has been able to generate new cost figures for comparison with DECC's current LCOE assumptions. The objective of the analysis was to identify where costs had changed and understand what has driven that change. Table 102 provides the current cost estimated for 2015, the DECC assumptions comparator and percentage change.

It should be noted that the cost data collected is for conversion projects that are either operational or under construction. New cost estimates for: pre-development; construction and infrastructure have been produced along with Arup's view on what has caused the overall change when the Arup 2011 figures are compared to the 2015 update:

- **Pre-development cost:** it was reported that the increase in cost was partially driven by increasing technical design and planning related costs. Again it should be noted that costs associated with technical planning and design elements are typically very bespoke to the plant under conversion. Despite only having a small dataset Arup considered it to be representative of potential conversion projects in the future.
- **Construction cost:** a comparison of the DECC LCOE data to the Arup 2015 update indicates a **48%** decrease in construction cost. The stakeholder engagement process indicated some learning effects associated with the deployment of new conversion. Some standardisation of the technology appears to have taken place along with improved delivery of projects.
- **Operating cost:** The data currently indicates that overall current opex costs have decreased from £70k/MWa to £54k/MWa, reflecting greater certainty with cost estimation. The change in cost has been driven by decreases in fixed and variable elements.

Table 102 Biomass Conversion Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	84	84	84	84
	Construction	£/kW	237	237	237	237
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**321**	**321**	**321**	**321**
	Total opex	**£MW**	**53,889**	**53,889**	**53,889**	**53,889**
	Fixed O&M	£/MW	22,812	22,812	22,812	22,812
	Variable O&M	£/MWh	1.3	1.3	1.3	1.3
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	11,534	11,534	11,534	11,534
	UoS	£/MW	10,528	10,528	10,528	10,528
DECC Current	Pre-development	£/kW	60	60	60	60
	Construction	£/kW	454	441	436	432
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**514**	**501**	**496**	**492**
	Total opex	**£/MW**	**70,261**	**70,418**	**70,575**	**70,733**
	Fixed O&M	£/MW	42,509	42,636	42,764	42,893
	Variable O&M	£/MWh	1.5	1.5	1.5	1.5
	Insurance	£/MW	1,340	1,344	1,348	1,352
	UoS	£/MW	18,079	18,079	18,079	18,079
	Pre-development	%	40%	40%	40%	40%

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	-48%	-46%	-46%	-45%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-38%**	**-36%**	**-35%**	**-35%**
	Total opex	%	**-23%**	**-23%**	**-24%**	**-24%**

Arup reviewed the estimates it produced against benchmark costs from publications and renewable market reports. The objective here was to provide validation of the findings and provide confidence around the observations to date. To understand the change in cost Arup analysed different development, construction and opex benchmark data where available for biomass conversion. Overall, the following was collected:

- **Construction costs:** comparator data was available from Poyry which estimated the range of cost to be from £250/kW to £450/kW. The 2015 estimate of £237/kW is close to the low end of the benchmark range.
- **Operating cost**: data was again available from Poyry which indicated cost to be £51k/MW and similar to Arup's 2015 medium estimate of £53k/MW. It was concluded that the operating cost value produced by the dataset appeared to be of the correct order.

9.7 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC's current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net power:** the average installed capacity is reported to have reduced from 900MW to 349MW, reflecting the current scale of conversion plant planned and under development.
- **LHV efficiency:** compared with DECC's existing assumptions, internal and stakeholder data indicated a small increase in LHV efficiency from 36% to 40%. Following internal discussions it is Arup's view that new plant could potentially achieve high-levels of efficiency up to 40%.
- **Availability:** plant availability data was reported by stakeholders but no load factor information provided. Arup reviewed and interpreted the availability data as equivalent to the net load factor i.e. the maximum time proportion a plant will generate in a year. For the purposes of the analysis it was assumed that availability is the same as 'load factor', defined under Section Three. For modelling purposes only availability was set at 100%.

- **Load factor:** the current load factor assumed by DECC is 65% which is at the low end of Arup's expected load factor range of 72% to 87%. Both external and internal data has indicated an overall increase which will overall cause a reduction in LCOE. A summary of the load factors used for the analysis are provided in **Appendix B.**

Table 103 Biomass Conversion Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	900.0	348.5	-551.5
Net LHV efficiency	%	36%	40%	12.7%
Availability	%	100%	100%	0.0%
Load factor (gross)	%	65%	79%	22.1%
Load factor (net)	%	65%	79%	22.1%

The assumed load factor is presented below on table 104 and an assumed installation lifetime of 15 years is used.

Table 104 Biomass Conversion Assumed Load Factor %

%	Biomass Conversion
Medium, gross	79.4%
Medium, net	79.4%

Data from internal and external benchmark sources (Poyry, Platts) were available and compared with the load factors from DECC's published sources including DUKES. It is expected that biomass conversion plant will operate on a similar basis to historic unconstrained coal plant i.e. achieving a load factor of 75% or greater. It is therefore Arup's view that the current load factor is representative.

9.8 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup has calculated LCOE for a conversion reference plant for a project starting in 2016 and commissioning (i.e. becoming operation in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Table 106 provide the LCOE results based on DECC's updated hurdle rate for the technology.

Table 105 Biomass Conversion LCOE 2016 – 2030, 2014 Real Prices* £'000/MW

£'000s/MW	2016	2020	2025	2030
Low	85	85	85	85
Medium	87	87	87	87
High	89	89	89	89

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 106 LCOE 2016 – 2030 (Biomass conversion), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	85	85	85	85
Medium	87	87	87	87
High	88	88	88	88

9.9 Comparison of DECC and Arup LCOE Values

Table 107 provides a comparison between LCOEs based on Arup's new cost data, DECC's current assumptions and discount rates. A summary of all the LCOE generated using DECC's current and new hurdle rates is presented in **Appendix I.**

For biomass conversion projects the data indicates that a project starting in 2016 and becoming operational by 2020 (two years pre-development and construction periods)[39] has an estimated LCOE of 23% less than current DECC estimates. As discussed above, the drivers of this reduction are mainly: decrease in construction and operating costs, increases in load factor and efficiency.

Table 107 Biomass Conversion Comparison Arup vs. DECC, 2014 Real Prices £/MWh

£/MWh	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	85	85	109	109	-21.7%	-21.7%
Medium	87	87	113	113	-22.7%	-22.7%
High	89	89	119	119	-25.8%	-25.8%

[39] The two year pre-development and construction assumption has been derived from stakeholder responses and internal data.

10 Energy from Waste (CHP)

10.1 Introduction

Energy from Waste ('EfW') and Energy from Waste CHP ('EfW CHP') involve the handling and combustion of residential and/or commercial waste to produce electricity or both electricity and heat. EfW plant is generally designed to produce baseload electricity, whereas EfW CHP plant is designed to produce electricity and supply heat.

In a similar way to dedicated biomass, EfW is an established technology that has been extensively researched, with a range of technology providers and developers. Arup understand that new technology is currently being trialled with a focus on improving efficiency and feedstock handling processes.

Since the Arup 2011 study deployment of EfW and EfW CHP has increased steadily with recent schemes designed to serve heat demands, supplying either steam or heat. A range of EfW plant scales have been delivered including the large-scale Runcorn EfW plant, Riverside Resource Recovery EfW plant, North Quay EfW plant. In addition, new small-scale EfW plant technology has been developed by QinteQ.

Future challenges for the technology include more efficient use of heat generated, improvements in plant efficiency and availability of waste feedstock. For the analysis generation cost data was supplied via internal, external and stakeholder data. It should be noted that very limited data was collected by the stakeholder engagement.

The 2015 Update analysis has indicated that cost has increased significantly. Arup has used a process of internal and external validation to review the internal and external cost data used in the analysis. Despite the large differences in cost Arup has concluded that the underlying data is representative of projects currently being developed.

For the analysis stakeholders have typically indicated that technical operational life ranges between 30 to 40 years, with a medium life of 35 years.

10.2 Data Collection

Arup collected data from internal, published and stakeholder sources including developers and utility companies. For EfW and EfW CHP 15 and 3 data points were collected respectively. Based on the data collection criteria outlined in Section 2, 14 EfW and 3 EfW CHP data points were assessed to be robust, representative and useful to the analysis. All costs produced during the analysis were compared with the original stakeholder data and the collected benchmarks.

For EfW and EfW CHP average installed electrical capacity was estimated to be 30MW. The data used for the analysis represents projects at various stages of development that are either operational, under construction or planned.

10.2.1 Capital Expenditure

Pre-development cost for EfW and EfW CHP were observed to have a wide range from £0.11m/MW to £0.39m/MW and £0.11m/MW to 0.23m/MW. The medium costs was estimated to be £0.23m/MW and £0.16m/MW respectively. For both forms of EfW the majority of pre-development cost is understood to be attributed to pre-licencing, technical and design.

For both forms of EfW the most significant costs are understood to be related to generation fuel processing and handling equipment. For the representative EfW and EfW CHP projects the medium construction cost are estimated to be £8.2m/MW and £10.5m/MW respectively. Other costs such as grid infrastructure represent an additional £0.15m/MW. By combining the pre-development, construction and infrastructure costs total capital costs are estimated to be £8.6m/MW and £10.8m/MW. Tables 109 to 110 provide total CHP capital cost on a full condensing and CHP-mode basis. Please see section 2 on the methodology applied to generate the estimates. A key finding is the wide range of capital costs. This is a result of a wide range of cost and small data sample collected. It should be noted that the data was reviewed internally and externally, providing comfort around the values generated.

Table 108 EfW Capital Costs (2015 Financial Close), 2014 Real Prices £'000/MW

£'000/MW	Energy from Waste
Low	4,795
Medium	8,582
High	13,097

Table 109 EfW CHP Capital Costs (2015 Financial Close), 2014 Real Prices Condensing £'000/MW

£'000/MW	Energy from Waste CHP
Low	9,054
Medium	10,779
High	12,807

Table 110 EfW CHP Capital Costs (2015 Financial Close), 2014 Real Prices CHP-mode £'000/MW

£'000/MW	Energy from Waste CHP
Low	10,590
Medium	13,773
High	16,542

Table 111 EfW Capital Cost Breakdown for a Medium Project %

Capital cost item	Energy from Waste
Pre-development	2.7%
Construction	95.5%
Infrastructure	1.8%

Table 112 EfW CHP, Condensing Capital Cost Breakdown for a Medium Project %

Capital cost item	Energy from Waste
Pre-development	1.5%
Construction	97.1%
Infrastructure	1.4%

Table 113 EfW CHP, CHP-mode Capital Cost Breakdown for a Medium Project %

Capital cost item	Energy from Waste
Pre-development	1.5%
Construction	96.7%
Infrastructure	1.8%

10.2.2 Capital Cost Learning Rate Assumption and Forecast

Stakeholders were asked to provide a view on what they considered to be the main cost drivers behind pre-development and construction costs. Based on stakeholder feedback and publically available literature an Arup view was formed on the future direction of capital cost. The analysis allowed a learning rate forecast to be developed and applied to the base 2015 cost figures. Respondents provided limited views on the future change and direction of cost. For the forecast Arup primarily used stakeholder views, internal research and information from published sources.

For the forecast EfW capital costs were broken down into components that included plant equipment, machinery, flue gas treatment, buildings and civils. The learning rate factor forecast was applied to each cost component with the exception of buildings and civils. For capital cost Arup has developed its adjustment factor based primarily on learning rate data from the literature review. By combining the published learning rate forecast along with the expectations of stakeholders, a weighted average adjustment factor was applied.

Arup’s review indicated potential cost reductions in flue gas treatment equipment and plant machinery. Limited learning effects were anticipated since EfW is already a relatively mature technology. **Appendix C**, provides a summary of the cost index forecast which has been applied. Based on an analysis of learning rates and deployment the decrease in capital cost is expected to be 1.5% by 2020, 2.7% by 2025 and 3.7% by 2030, which is equal to an annual reduction of -0.2%. The learning rates has been estimated based on data from stakeholder, IEA and a UK focussed literature review. To obtain our rate 1.5GW of EfW plant is expected to be deployed by 2030

Table 114 EfW Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	4,795	4,725	4,671	4,625
Medium	8,582	8,458	8,360	8,280
High	13,097	12,908	12,760	12,637

Table 115 EfW CHP Capital Cost Forecast 2015 – 2030 Condensing Mode, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	9,054	8,920	8,815	8,728
Medium	10,779	10,622	10,497	10,394
High	12,807	12,620	12,473	12,351

Table 116 EfW CHP Capital Cost Forecast 2015 – 2030 CHP-mode, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	10,590	10,434	10,311	10,209
Medium	13,773	13,572	13,413	13,282
High	16,542	16,302	16,113	15,957

10.3 Operating Cost

Labour and chemical costs were noted as being the most significant variable for future operating costs. In addition, exchange rates could also potentially have a material impact on the cost of replacement parts as many are imported from abroad. The technology is well established in the UK with a large number of developers with significant experience in operating plant. It was concluded that only small learning effects can be expected. Tables 117 and 119 provides the current range, tables 120 to 122 and forecast of operating cost to 2030.

10.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs the literature and stakeholder engagement review indicated that cost is expected to marginally decrease going forward. Potential reductions in O&M fixed, variable and insurance costs are expected going forward. For grid costs Arup used its own UoS (TNUoS and DUoS) forecast assumptions, insurance was linked to capital costs, fixed and variable opex were linked to the views reported by stakeholders.

Appendix C provides a summary of the cost index forecast applied to EfW and EfW CHP. Based on an analysis of learning rates and deployment the reduction in opex cost is expected to be 2.7% by 2020, 4.2% by 2025 and 5.6% by 2030.

Table 117 EfW Operating Cost (EfW), 2014 Real Prices £'000/MW

£'000s/MW	Energy from Waste
Low	101
Medium	367
High	631

Table 118 EfW CHP Operating Cost Condensing Mode, 2014 Real Prices £'000/MW

£'000s/MW	Energy from Waste CHP
Low	287
Medium	516
High	710

Table 119 EfW CHP Operating Cost CHP-mode, 2014 Real Prices £’000/MW

£’000s/MW	Energy from Waste CHP
Low	334
Medium	648
High	900

Table 120 EfW Operating Cost Forecast 2016 – 2030, 2014 Real Prices £’000/MW

£’000s/MW	2015	2020	2025	2030
Low	101	98	97	95
Medium	367	358	353	348
High	631	615	606	598

Table 121 EfW CHP Operating Cost Forecast 2016 – 2030 CHP Condensing mode, 2014 Real Prices £’000/MW

£’000s/MW	2015	2020	2025	2030
Low	287	279	275	271
Medium	516	503	496	489
High	710	691	682	672

Table 122 EfW Operating Cost Forecast 2016 – 2030 CHP-mode, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	334	325	320	315
Medium	648	632	623	614
High	900	876	864	852

10.4 EfW Fuel Prices

Arup collected and reviewed EfW gate fee price data from stakeholders, benchmarks and published sources. Data collected via stakeholder and internal sources only represented a small sample of four data points.

After an internal review of published sources it was concluded that WRAP's Gate Fee Report provided the most representative view of industry gate fees. For example, WRAP's data is based on around 80 gate fee data points, 25 of which are used to estimate gate fee for EfW projects that commenced operation post-2000. It was therefore concluded that for the LCOE analysis Arup would utilise WRAP's 'post-2000' gate fee for EfW plant. The following has been assumed to generate a £/MWh based for the LCOE model:

- A GCV of 11.0GJ/tonne[40];
- To convert from GJ to MWh a conversion of 3.6 is applied.

Arup calculated a minimum, average and maximum £/MWh value based on WRAP data. Table 123 below provides the forecast to 2030. The medium value of £30.76/MWh can be compared to DECC's assumption of £22.86/MWh and indicates an overall increase in gate fees received by EfW plant operators. For LCOE modelling purposes it is important to note that gate fees are treated as an income and are netted off LCOE. Gate fees are also assumed to represent long-term contracts, therefore, EfW gate fees are assumed to remain constant across the review period. Based on Arup's experience the typical EfW waste supply contract is typically between 20 and 30 years in length.

The data indicated that there has been a 35% increase in gate fees. The change in price can be attributed to EfW operators obtaining higher gate fees and potentially

[40] EfW gate fees are based on data from WRAP's Gate Fees report (low, medium and high) and assumed GCV of 11GJ/tonne. The current assumed GJ/tonne value should cover current average fuel mix, there is however uncertainty over future fuel mix.

better commercial contracts. Table 123 provides a summary of the estimated gate fee prices paid for by operators.

Table 123 EfW Gate Fee Assumptions Forecast 2015 – 2030, 2014 Real Prices £/MWh

£/MWh	2015	2020	2025	2030
Low	-36.65	-36.65	-36.65	-36.65
Medium	-30.76	-30.76	-30.76	-30.76
High	-20.29	-20.29	-20.29	-20.29

10.5 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these to existing DECC assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Tables 124 to 126 provide current cost estimates for 2015, the DECC assumptions comparator and percentage change.

It should be noted that the number of data points captured for the analysis of EfW and EfW CHP is relatively small. Therefore, a comparison between the existing DECC assumptions and the Arup 2015 figures was difficult. The cost data received has been validated internally and externally with DEFRA.

It should be noted that the cost data collected is for EfW and EfW CHP plant that has recently reached final commissioning or is currently under development. Arup has used DECC's existing cost estimates and compared these with those generated by the 2015 update. The following provides Arup's view on what has caused the change in cost between DECC's current cost assumptions and Arup's 2015 work:

- **Pre-development cost:** no pre-development cost data were available for comparison with the Arup 2015 figures, therefore Arup used the current estimates produced by the 2015 Update.
- **Construction cost:** EfW is a relatively well known technology with costs not expected to change significantly, but comparison of the DECC and the Arup 2015 update indicates a large increase in construction cost of around **65%** for both EfW and EfW CHP costs. Following an internal and external review of the cost data collected it was determined that the new construction cost estimate was representative for new projects. It is however difficult to make an accurate comparison between the Arup 2011 and 2015 Update data. A key difference behind the difference is the scale of the dataset used.

- **Operating cost:** key drivers are understood to be labour costs (which have remained relatively flat), the price of treatment chemicals and disposal of hazardous waste. Overall operating costs are reported to have decreased by **13%** for EfW and increases marginally for EfW CHP (condensing) at **1%**. It should be noted that operating costs will vary depending on the type of fuel input and the waste handling process at the EfW plant.
- Although there was limited data available UoS for EfW was noted as being low when compared to other forms of renewable fuel plant including ACT; AD; dedicated biomass and biomass conversion. The current UoS cost estimates are based on real projects. Arup is therefore confident in the figures that are being used.

Table 124 EfW Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	228	228	228	228
	Construction	£/kW	8,200	8,076	7,978	7,898
	Infrastructure	£'000	4,649	4,649	4,649	4,649
	Total capex	**£/kW**	**8,582**	**8,458**	**8,360**	**8,280**
	Total opex	**£MW**	**366,928**	**357,731**	**352,875**	**348,020**
	Fixed O&M	£/MW	139,458	135,649	133,637	131,626
	Variable O&M	£/MWh	23.4	22.7	22.4	22.1
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	30,476	29,644	29,204	28,765
	UoS	£/MW	16,686	16,686	16,686	16,686
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	5,039	4,966	4,938	4,915
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**5,039**	**4,966**	**4,938**	**4,915**
	Total opex	**£/MW**	**420,144**	**421,196**	**422,250**	**423,306**
	Fixed O&M	£/MW	230,722	231,299	231,878	232,459
	Variable O&M	£/MWh	25.3	25.4	25.4	25.5
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
	Pre-development	%	-	-	-	-

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	63%	63%	62%	61%
	Infrastructure	%	-	-	-	-
	Total capex	%	**70%**	**70%**	**69%**	**68%**
	Total opex	%	**-13%**	**-15%**	**-16%**	**-18%**

Table 125 EfW CHP Cost Comparison between Arup 2015 and DECC Current Condensing Mode, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	164	164	164	164
	Construction	£/kW	10,462	10,304	10,179	10,076
	Infrastructure	£'000	4,649	4,649	4,649	4,649
	Total capex	**£/kW**	**10,779**	**10,622**	**10,497**	**10,394**
	Total opex	**£MW**	**515,961**	**502,692**	**495,687**	**488,683**
	Fixed O&M	£/MW	120,182	116,899	115,165	113,432
	Variable O&M	£/MWh	41.8	40.7	40.1	39.5
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	66,979	65,149	64,183	63,218
	UoS	£/MW	16,686	16,686	16,686	16,686
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	6,358	6,266	6,231	6,202
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**6,358**	**6,266**	**6,231**	**6,202**

	Assumption	Unit	2015	2020	2025	2030
	Total opex	**£/MW**	**509,266**	**510,540**	**511,818**	**513,099**
	Fixed O&M	£/MW	279,663	280,363	281,065	281,768
	Variable O&M	£/MWh	30.7	30.7	30.8	30.9
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
% Change	Pre-development	%	-	-	-	-
	Construction	%	65%	64%	63%	62%
	Infrastructure	%	-	-	-	-
	Total capex	%	**70%**	**69%**	**68%**	**68%**
	Total opex	%	**1%**	**-2%**	**-3%**	**-5%**

Table 126 EfW CHP Cost Comparison between Arup 2015 and DECC Current, CHP-mode), 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	208	208	208	208
	Construction	£/kW	13,315	13,114	12,955	12,824
	Infrastructure	£'000	5,917	5,917	5,917	5,917
	Total capex	**£/kW**	**13,773**	**13,572**	**13,413**	**13,282**
	Total opex	**£MW**	**648,428**	**631,541**	**622,626**	**613,711**
	Fixed O&M	£/MW	152,959	148,780	146,574	144,368
	Variable O&M	£/MWh	53.2	51.8	51.0	50.3
	BSUoS	£/MWh	1.9	1.9	1.9	1.9

	Assumption	Unit	2015	2020	2025	2030
	Insurance	£MW	85,246	82,917	81,688	80,459
	UoS	£/MW	16,686	16,686	16,686	16,686
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	6,358	6,266	6,231	6,202
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**6,358**	**6,266**	**6,231**	**6,202**
	Total opex	**£/MW**	**509,266**	**510,540**	**511,818**	**513,099**
	Fixed O&M	£/MW	279,663	280,363	281,065	281,768
	Variable O&M	£/MWh	30.7	30.7	30.8	30.9
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
% Change	Pre-development	%	-	-	-	-
	Construction	%	109%	109%	108%	107%
	Infrastructure	%	-	-	-	-
	Total capex	%	**117%**	**117%**	**115%**	**114%**
	Total opex	%	**27%**	**24%**	**22%**	**20%**

Arup reviewed the estimates it produced against benchmark cost data from published sources. The objective was to provide validation of the findings and provide confidence around the observations made. To understand the change in cost Arup has analysed different development, construction and opex benchmarks for EfW and EfW CHP. Overall, the following was observed when compared to the Arup 2015 figures:

- **Construction costs:** comparator data was available from WEC which estimated the range of cost to be £3,202/kW and £3,491/kW. The 2015 estimate of £8,200/kW is significantly different from the external benchmarks for EfW. Although there is a surprisingly large difference in cost between the benchmark WEC data and Arup's 2015 data, Arup's internal and external validation (including DEFRA) provided confidence.

- **Operating cost**: data was available from WEC which indicated fixed operating cost to range between £96k/MW and £155k/MW. Arup's 2015 update value is £139k/MW which is less than DECC's current estimate but between the values provided via the external reports. It was concluded that the operating cost value produced by the dataset was of the correct order when compared to the available external data.

10.6 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC's current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net Power:** the overall installed capacity of plant changed by only a small absolute amount indicating that future plant can be expected to be of a similar scale. The data were validated internally and is understood to be representative of future plant deployment going forward.

- Steam output was also noted as increasing slightly between DECC's current and Arup's 2015 updated figure 23.6MWth to 28.1MWth.

- **LHV efficiency:** efficiency figures were validated internally and reviewed with DECC. Importantly, the data has indicated a marginal improvement in net LHV efficiency from 24% to 28%.

- **Availability:** data was available from stakeholders and external sources. Overall for EfW and EfW CHP plant availability has improved marginally from 90% to 93%. The increase is assumed to reflect improvements in the way developers are operating their assets, reducing plant downtime and maintenance regimes.

- **Load factor:** for EfW is understood to have decreased by around 5% when compared on a net basis. The current figure of 81% appears to be close to the expected range of 80% to 85%. The data indicated an overall decrease which is expected to result in an increase in LCOE. A summary of the load factors used for the analysis is provided in **Appendix B.**

Table 127 EfW Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	33.00	30.17	-2.83
Net LHV efficiency	%	24%	28%	16.4%
Availability	%	90%	93%	3.4%
Load factor (gross)	%	95%	88%	-7.8%
Load factor (net)	%	86%	81%	-4.7%

Table 128 EfW CHP Technical Assumptions, Condensing Basis

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	27.50	30.17	2.67
Net LHV efficiency	%	20%	28%	41.1%
Availability	%	90%	93%	3.4%
Load factor (gross)	%	95%	88%	-7.8%
Load factor (net)	%	86%	81%	-4.7%

Table 129 EfW CHP Technical Assumptions, CHP-mode Basis

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	27.50	23.71	-3.80
Average steam output	MWth	23.61	28.06	4.45
Net LHV efficiency	%	20%	22%	11.1%
Availability	%	90%	93%	3.4%
Load factor (gross)	%	95%	88%	-7.8%
Load factor (net)	%	86%	81%	-4.7%

The assumed gross load factor is provided in Table 130 below and has an assumed installation lifetime of 35 years for both EfW and EfW CHP is used.

Table 130 Assumed Gross Load Factor

%	EfW and EfW CHP
Medium, gross	87.6%
Medium, net	81.5%

Two useful sources of data include load factors figures produced by BNEF and DUKES which are 80% and 84% respectively. The LCOE modelling load factor was based on stakeholder data for the minimum, average and maximum for 2015 onwards. Arup did not anticipate any large change in the load factor. When the load factor is compared on a net basis (81%) it sits between the benchmark range.

10.7 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for an EfW reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Tables 134 to 136 provide the LCOE results based on DECC's updated hurdle rate for the technology.

Based on DECC's updated hurdle rates the low LCOE for EfW shows a negative value. It has been concluded that it is the result of a wide range in cost and availability of data. Therefore, the low LCOE value must be viewed with a degree of caution since the number of data points used for the analysis is small.

Table 131 EfW LCOE 2016 – 2030, 2014 Real Prices*£/MWh

£/MWh	2016	2020	2025	2030
Low	18	20	18	16
Medium	81	83	80	77
High	155	158	154	151

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 132 EfW CHP LCOE 2016 – 2030 Condensing Mode, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	111	117	110	107
Medium	140	147	139	136
High	174	182	173	169

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table.*

Table 133 EfW CHP LCOE 2016 – 2030, CHP-mode, 2014 Real Prices* £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	89	99	86	81
Medium	142	154	139	134
High	189	202	186	180

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 134 LCOE 2016 – 2030 (Energy from Waste), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	-2	-1	-3	-4
Medium	43	45	43	41
High	98	100	97	95

Table 135 LCOE 2016 – 2030 (Energy from Waste CHP, Condensing), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	96	98	84	92
Medium	121	124	120	117
High	152	155	151	148

Table 136 LCOE 2016 – 2030 (Energy from Waste CHP, CHP-mode), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	71	77	69	64
Medium	119	125	116	111
High	161	167	158	153

10.8 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup's new cost data, DECC's current assumptions and discount rates. A summary of all the LCOEs generated using DECC's current and new hurdle rates are presented in **Appendix I.**

For EfW and EfW CHP the data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE +100% higher than current DECC figures. Part of the large increase in cost has been offset by a small reduction in operating costs. However the main factor which has caused the increase in LCOE is a result of an increase in construction costs. A published set of benchmarks from WEC construction cost indicates a significant different (£3,491/kW and £3,202/kW) when compared to the central estimated cost of £8,200/kW. It should be noted that despite the large difference in cost, the estimate value has been reviewed internally and externally with DEFRA and assessed to be representative for the Study. WEC also publishes a range of fixed operating costs equal to £96k/MW to £155k/MW, Arup's estimated figure of £139k/MW sits between the benchmark range providing comfort around the value used for LCOE modelling purposes. Please note that DECC's current LCOE figures are for EfW CHP operating in CHP-mode. No direct comparator for condensing mode CHP is available.

Key cost drivers include an increase construction cost a small reduction in load factor. For comparison purposes the current DECC figures have been inflated from 2012 to 2014 prices.

Table 137 EfW Comparison Arup vs. DECC, 2014 Real Prices £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	18	20	25	26	-27.2%	-22.1%
Medium	81	83	31	31	161.3%	165.2%
High	155	158	36	36	331.6%	335.1%

Table 138 EfW CHP Comparison Arup vs. DECC, CHP-mode, 2014 Real Prices £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	89	99	19	19	377.4%	421.8%
Medium	142	154	30	31	367.8%	400.2%
High	189	202	42	43	347.6%	374.2%

11 Dedicated Biomass

11.1 Introduction

Over the last five years there has been significant potential for new electricity generation from conventional dedicated biomass plants as a result of the constraints imposed by the LCPD and IED upon fossil fuel burning plants. In 2010 dedicated biomass installed capacity accounted for 394MW, growing to 2,244MW by 2015[41]. It should be noted that no stakeholders provided a view on the barriers to deployment. However barriers to deployment have been reported in literature and include supply chain[42] and environmental factors.

Relative to other renewable technologies dedicated biomass is one of the oldest and most established forms of generation. There are a range of technology providers and developers now established within the market, demonstrating their ability to deliver dedicated biomass projects. No significant new innovations are expected within the dedicated biomass market. However, key challenges for the technology do remain including improvements in generation efficiency, obtaining a sustainable fuel supply and locating plants close to grid connections.

For the previous Arup 2011 study DECC requested that data was collated and split into the following installed capacity ranges: <50kW, 50kW to 5MW; 5MW to 50MW; 50MW to 100MW; and >100MW. For the 2015 Update Arup was only able to collect data on projects that had an installed capacity of <50MW. No data was available for plants with an installed capacity of >50MW. As a result Arup recommend one combined scale for the analysis:

- <50MW dedicated biomass

It should be noted that no data was collected via the stakeholder engagement. As a result of the data shortage Arup used alternative published sources, benchmarks and internal sources of information. For the analysis dedicated biomass plant is assumed to have a technical asset life of 25 years.

11.2 Data Collection

Following the process outlined in Chapter Three the generation information was collected via stakeholders, published reports and internal sources of data. However, no data was collected via the stakeholder engagement, so the analysis relied on published reports, benchmarks and internal sources of information..

Overall data used for the analysis included 4 internal projects and 3 benchmarks, yielding 7 project data points.

Based on the data collection criteria outlined in Section 2 all 7 data points were assessed to be robust, representative and useful to the analysis. All results

[41] http://www.ref.org.uk/generators/group/index.php?group=yr

[42] Deloitte, Knock on Wood Is Biomass the Answer to 2020

produced during the analysis were compared with the historic data and tested against internal knowledge.

In terms of installed capacity the four internal project data points (where installed capacity data was available) represented 120MW of projects at various stages of development (operational, under construction and planned) and located across the UK. Following the data analysis and validation process the low and high installed capacity for dedicated biomass was 15MW to 35MW. Average capacity was calculated to be equal to 23MW. Stakeholders typically assumed a project operational life of 25 years

11.2.1 Capital Expenditure

Pre-development cost was estimated to vary significantly between £0.08m/MW to £0.16m/MW, with a medium cost of £0.11m/MW. The majority of spend is understood to be allocated to pre-licensing, planning and technical development. For all forms of dedicated biomass the most significant costs relate to generation and biomass handling equipment. Overall the technology of burning biomass is a relatively mature and a similar level of technical development as other technologies such as EfW. It was determined that dedicated biomass is now a relatively well known technology with little scope for improvement. Construction cost has been estimated to range between £2.4m/MW and £3.4m/MW. For a medium project construction cost is equal to around £2.9m/MW. A comparison of the DECC LCOE data and the Arup 2015 update indicates a 22% reduction in construction cost.

Other costs such as grid connection, civil infrastructure representing around £0.02m/MW. By combining pre-development, construction and infrastructure costs the total capital cost is £3.0m/MW. Variation in capital costs is reported to be driven by three factors including feedstock type, process configuration, and economies of scale.

The reduction in construction cost is also reflected in the current benchmarks provided via IRENA, WEC and BNEF. The Arup cost is noted as being close to the IRENA value of £2.8m/MW which provides a degree of assurance on the cost produced. Based on the available data and our knowledge that dedicated biomass costs are relatively well know with marginal scope for improvement, the following 2015 cost figures were developed for LCOE modelling purposes.

Table 139 Dedicated Biomass Capital Costs (2015 Financial Close), 2014 Real Prices £'000/MW

£'000/MW	Dedicated Biomass
Low	2,452
Medium	3,010
High	3,552

Table 140 Dedicated Biomass Capital Cost Breakdown for a Medium Project %

Capital cost item	Dedicated Biomass
Pre-development	3.7%
Construction	95.6%
Infrastructure	0.6%

11.2.2 Capital Cost Learning Rate Assumption and Forecast

For other renewable technologies Arup was able to include the views of stakeholders and understand expectations on the future direction of construction and operational cost. However, in the absence of any stakeholder data Arup relied upon internal and external sources of information for its capital cost forecast and the learning rates. For the forecast Arup utilised data from sources including National Grid's Future Energy Scenarios.

From a construction cost perspective the main cost drivers are understood to be exchange rates (a lot of generation equipment is imported), labour, commodity prices and chemical prices. Despite the technology being well understood it was determined that was some marginal scope exists to reduce construction cost. The key drivers expected to cause a reduction in construction cost include efficiency in project delivery and some small technical improvements. Table 141 provides the forecast Arup has produced to date.

Appendix C, provides a summary of the cost index forecast for dedicated biomass plant applied to construction cost. Based on an analysis of learning rates and deployment the reduction in cost is expected to be 1.6% by 2020, 2.9% by 2025 and 3.9% by 2030, which is equal to an annual reduction of -0.3%. The learning rates has been estimated based on data from the IEA, UK focussed literature review and National Grid’s Future Energy Scenarios. To obtain our rate 3GW of dedicated biomass is expected to be deployed by 2030

Table 141 Dedicated Biomass, Capital Cost Forecast 2015 – 2030, 2014 Real Prices £’000/MW

£’000s/MW	2015	2020	2025	2030
Low	2,452	2,414	2,384	2,360
Medium	3,010	2,964	2,928	2,898
High	3,552	3,498	3,455	3,420

11.3 Operating Cost

Operational costs show 20% to 30% difference around the medium cost. The relatively small variance in cost implies that for dedicated biomass plant operating cost has become more certain. The conclusion reached here must however be viewed with a degree of caution since the number of data points used for the analysis is small and does not contain any stakeholder specific data.

Table 142 provides an indication of the variation in operating cost between low, medium and high. Overall cost ranges from £118k/MW to £189k/MW, average operating cost is around, £147k/MW and is expected to be mainly driven by project specific conditions, availability of equipment and skilled labour.

11.3.1 Operating Cost Learning Rate Assumption and Forecast

Operating costs for dedicated biomass plant are primarily driven by the labour required to operate and maintain production, generation equipment and waste disposal. Overall, following an internal review it is Arup expectation that operating costs will remain flat.

Table 142 Dedicated Biomass, Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	Dedicated Biomass
Low	118
Medium	147
High	189

Table 143 Dedicated Biomass, Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	118	118	118	118
Medium	147	147	147	147
High	189	189	189	189

11.4 Biomass Fuel Prices

Arup was unable to collect new biomass fuel price data for dedicated biomass projects. However, following an internal and external review it was concluded that dedicated biomass plant with an installed capacity of <50MW is likely to use UK sourced waste wood as the main fuel input. Therefore, Arup has used the same fuel price assumptions as biomass CHP i.e. waste wood is its primary fuel input[43].

The biomass fuel data is based on the same data as biomass CHP which comprise of five stakeholder and four internal benchmarks. The use of waste wood in plants with an installed capacity of <50MW conformed with Arup's view.

The following has been assumed to generate a £/MWh value for the LCOE model:

- A GCV of 12.5 GJ/tonne[44];
- To convert from GJ to MWh a conversion of 3.6 is applied..

[43] Dedicated biomass fuel prices and GCVs are based on same data as Biomass CHP i.e. nine data points (stakeholder plus internal data). Assumed GCV of 12.5GJ/tonne.
[44] It should be noted that Whitaker and Murphy (2009) provide an average moisture content for all biomass waste of 29%, which would have an energy content of 12.5GJ/tonne.

Arup has been able to estimate a low, medium and high biomass price presented on table 144 below. The medium value of £9.66/MWh can be compared to DECC's current assumption of £22.63/MWh. The large fall in waste wood fuel prices can be attributed to improvements in UK biomass supply chain, availability of waste wood fuel and competition within the biomass supply sector.

Table 144 Biomass Fuel Price Assumptions Forecast 2015 – 2030, 2014 Real Prices £/MWh

£/MWh	2015	2020	2025	2030
Low	3.55	3.55	3.55	3.55
Medium	9.66	9.66	9.66	9.66
High	31.20	31.20	31.20	31.20

11.5 Cost Breakdown

Based on the data collected Arup was able to generate new cost figures and compare these with existing DECC assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Table 145 provides current cost estimates for 2015, DECC's current assumption and the percentage change.

It should be noted that the number of data points captured for the analysis is small and therefore the cost estimates produced here should be interpreted with a degree of caution. The cost data that was collected has been validated internally for use in the LCOE analysis.

The cost data collected for the analysis is primarily based on internal and external benchmarks. Arup has used DECC's existing cost estimates and compared these with those generated by the updated analysis. The following provides Arup's view on what has caused the change in cost:

- **Pre-development cost:** Arup understand that the requirement around consenting, planning and finding sites for development has remained the same. To a degree this is reflected in a small **13%** increase in cost.
- **Construction cost:** a comparison of the DECC assumptions and the Arup 2015 update indicates a large overall decrease in construction cost of around **20%**. Dedicated biomass is a relatively well known technology with cost not expected to change significantly. A minor part of the decline can be attributed to infrastructure cost being separated from construction cost in the 2015 update. These costs had previously been wrapped into the DECC construction

cost estimate. The key driver leading to a reduction in cost is understood to be improvements in EPC delivery and improvements in the supply chain including availability of parts, equipment and skilled labour.

- **Operating cost:** cost is understood to be driven by labour (which has remained relatively flat), the price of treatment chemicals e.g. lime carbon and the disposal of hazardous waste. Overall operating cost are reported to have decreased by around **18%**.

- Operating cost will vary depending on the type of fuel input into the dedicated biomass. For example, waste wood typically has a higher cost since a testing and cleaning processes are required to be in place, more refined fuels such as wood pellets are understood to require a less rigorous inspection process.

- No UoS cost data was available from internal or external sources of information. Therefore, Arup used the UoS cost estimate from biomass CHP to fill this gap.

Table 145 Dedicated Biomass, Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	113	113	113	113
	Construction	£/kW	2,879	2,833	2,797	2,767
	Infrastructure	£'000	422	422	422	422
	Total capex	**£/kW**	**3,010**	**2,964**	**2,928**	**2,898**
	Total opex	**£MW**	**146,601**	**146,601**	**146,601**	**146,601**
	Fixed O&M	£/MW	65,499	65,499	65,499	65,499
	Variable O&M	£/MWh	5.8	5.8	5.8	5.8
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	11,534	11,534	11,534	11,534
	UoS	£/MW	12,921	12,921	12,921	12,921
DECC Current	Pre-development	£/kW	100	100	100	100
	Construction	£/kW	3,683	3,608	3,574	3,539
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**3,783**	**3,708**	**3,673**	**3,639**
	Total opex	**£/MW**	**177,749**	**174,310**	**172,818**	**171,338**
	Fixed O&M	£/MW	115,444	113,189	112,211	111,241
	Variable O&M	£/MWh	5.5	5.4	5.4	5.3
	Insurance	£/MW	17,143	16,808	16,663	16,519
	UoS	£/MW	1,700	1,700	1,700	1,700
	Pre-development	%	13%	13%	13%	13%

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	-22%	-21%	-22%	-22%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-20%**	**-20%**	**-20%**	**-20%**
	Total opex	%	**-18%**	**-16%**	**-15%**	**-14%**

Arup reviewed the estimates it produced against benchmark cost data from published sources. The objective here was to provide validation of the findings and provide confidence around the observations made. To understand the change in cost Arup analysed different development, construction and opex benchmark data for dedicated biomass. The following was observed:

- **Construction costs:** cost comparator data was available from BNEF, WEC and IRENA which estimated the range of cost to be £3,342/kW, 3,294/kW, £2,788/kW respectively. The 2015 estimate of £2,879/kW sits toward the low end of the external range and appears to follow the trend in cost reduction observed.
- **Operating cost**: data was available from WEC and BNEF which indicated that fixed operating are between £96k/MW and £52/MW. Arup's 2015 update for fixed operating cost is £65k/MW which is less than DECC's current estimate but between the two benchmarks provided via the external data. In addition, Arup benchmark comparators for variable O&M were also available from IRENA, BNEF and Lazard, indicated values of £3/MWh, £8/MWh and £10/MWh. The 2015 Update for variable O&M was estimated to be £6/MWh which sits between the low and high benchmarks values. Based on external data it was concluded that the operating cost values produced by the 2015 update were of the correct order.

11.6 Technical Assumptions

Arup was able to carry out a comparison with DECC's current technical assumptions and those used in Arup's 2015 updated analysis. In the absence of stakeholder data the analysis relied on data from published reports, benchmarks and internal source of information. The following provides a summary of the observations made.

- **Net Power:** the overall scale of plant has reduced in scale from 34.0MW to 22.9MW. The change potentially reflects the scale of plants currently being delivered with developers understood to be focussed on developing smaller scale sites.

- **LHV efficiency:** the efficiency estimate has been validated internally and externally with DECC. Importantly, based on the available information efficiency appears to have marginally reduced from 31% to 29%. The observed change in efficiency is assessed to be a result of the small dataset collected rather than a change in the underlying technology. This small change in efficiency is expected to have a marginal effect on LCOE.
- **Availability:** for dedicated biomass plant availability has improved marginally from 90% to 94%. The increase is assumed to reflect progress in the way developers are operating generation assets, reducing plant downtime and improving maintenance regimes.
- **Load factors:** for dedicated biomass Arup understand that net load factors have decreased marginally by around 7% to 84%. In comparison with other technologies such as EfW and biomass CHP the load factor is of a similar order; 81% and 80% respectively. The change is expected to result in an increase in LCOE. A summary of the load factors used in the analysis are provided in **Appendix B.**

Table 146 Dedicated Biomass Technical Assumptions Full Condensing Basis

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	34.00	22.89	-11.12
Net LHV efficiency	%	31%	29%	-5.0%
Availability	%	90%	94%	4.6%
Load factor (gross)	%	100%	89%	-10.7%
Load factor (net)	%	90%	84%	-6.6%

The assumed gross load factor is provided on Table 147 below and has an assumed installation lifetime of 25 years for both dedicated biomass.

Table 147 Dedicated Biomass Assumed Gross Load Factor %

%	Dedicated Biomass
Medium, gross	89.3%
Medium, net	84.1%

Benchmark data indicated a range of load factors of 85% to 96%. As a result of limited data the load factor is assumed to be held constant with no change over time.

11.7 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for a dedicated biomass reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Tables 149 provide the LCOE results based on DECC's updated hurdle rate for the technology.

Table 148 Dedicated Biomass, LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	97	97	97	96
Medium	107	108	107	106
High	117	118	117	116

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 149 LCOE 2016 – 2030 (Dedicated Biomass), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	88	88	88	87
Medium	97	96	96	95
High	104	104	103	103

11.8 Comparison of DECC and Arup LCOE Values

The following summary table provides a comparison between LCOE based on Arup's new cost data, DECC's current assumptions and discount rates. A summary of all the LCOEs generated using DECC's current and new hurdle rates is presented in **Appendix I.**

Overall, for dedicated biomass the data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE -17% lower than current DECC figures. For comparison purposes the current DECC figures have been inflated from 2012 to 2014 prices.

Table 150 Dedicated Biomass Comparison Arup vs. DECC, 2014 Real Prices £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	97	97	109	110	-11.2%	-11.3%
Medium	107	108	129	129	-16.7%	-16.8%
High	117	118	155	155	-24.2%	-24.3%

12 Anaerobic Digestion

12.1 Introduction

Anaerobic digestion ('AD') is the biological degradation of biodegradable organic material by micro-organisms in the absence of oxygen, resulting in a reduction of the quantity of organic material and the production of biogas.

AD processes are widely employed by the water industry for the stabilisation of sewage sludge. In addition to sewage sludge a wide range of alternative feedstocks can be used in AD systems such as farmyard waste, crops and feedstock. Over the last five years the AD sector has seen a significant increase in deployment with installed capacity increasing from 30MW in 2009 to 216MW by 2014.

In a similar way to biomass CHP, dedicated biomass and EfW technologies it is understood that AD is one of the more proven technologies with limited scope for further improvement in technology cost. Key challenges for AD include locating suitable sites and securing reliable feedstock supplies and contracts.

For the analysis cost data was supplied via a limited number of stakeholder projects, internal and published sources of data. For the 2011 Study Arup was able to disaggregate the data between <1MW and 1MW to 5MW. For this study, Arup was requested to analyse projects that have installed capacities >5MW for this study. Unfortunately the stakeholder engagement was not able to provide information on projects at the required scale. Arup has therefore combined the stakeholder, internal and external data to generate sources to generate the cost and technical parameters for the following:

- AD 1 – 5MW;
- AD CHP.

12.2 Data Collection

Data was collected from stakeholder, internal and external sources. Arup contacted manufacturers, developers, trade associations and utility companies. Overall 15 data points were collected for the analysis. The sample used for the analysis comprised of 9 AD plants in the 1-5MW range and 6 AD CHP.

Based on the data collection criteria outlined in Chapter Three, all 15 data points were assessed to be robust, representative and useful for the analysis. All results produced during the analysis were compared with the original stakeholder data and benchmarks.

In terms of installed capacity the AD and AD CHP data points represented 14.0MW and 13.8MW of projects at various stages of development (operational, under construction and planned). The average capacity of each was estimate to be 2.4MW and 1.9MW for AD and AD CHP respectively. It should be noted that the data sample used for the analysis is based mainly on cost data for farm / crop based AD plant and only limited information available for AD CHP plant.

12.2.1 Capital Expenditure

For both AD and AD CHP pre-development costs were reported to range between £0.02m/MW and £0.06m/MW and a medium cost of £0.04m/MW. Cost was observed to be split equally between pre-licensing, planning and technical development. The collated data indicated pre-development costs varied widely +/-40%. It should be noted that for AD CHP no pre-development cost data was available, in the absence of data Arup assumed the same pre-development cost for both AD and AD CHP. The wide range in cost is likely to be the result of the small data sample.

Variation in construction costs was reported to be driven by three factors including feedstock type, process configuration and economies of scale. For all forms of AD and AD CHP the most significant cost relate to the generation and fuel processing equipment. For AD and AD CHP the average (‘medium’) project capital cost is equal to around £2.9m/MW and £4.1m/MW respectively. A comparison of the current DECC construction cost data and the Arup 2015 update indicates a 31% and 4% reduction in construction cost for AD and AD CHP respectively.

Other costs such as infrastructure represent around additional £0.03m/MW and £0.04m/MW. Please note that a combined arithmetic average infrastructure cost was used for both AD and AD CHP.

Combining the pre-development, construction and infrastructure costs capital cost is equal to £3.2/MW and £4.6m/MW for AD and AD CHP respectively.

Table 151 AD Capital Costs (2015 Financial Close), 2014 Real Prices £’000/MW

£’000/MW	AD
Low	2,425
Medium	3,190
High	4,223

Table 152 AD CHP Capital Costs (2015 Financial Close), 2014 Real Prices Full Condensing and CHP-mode £'000/MW

£'000/MW	AD CHP
Low	3,776
Medium	4,556
High	5,615

Table 153 AD Capital Cost Breakdown for a Medium Project %

Capital cost item	Anaerobic Digestion
Pre-development	1.2%
Construction	89.4%
Infrastructure	9.4%

Table 154 AD CHP Capital Cost Breakdown for a Medium Project %

Capital cost item	Anaerobic Digestion
Pre-development	0.9%
Construction	90.8%
Infrastructure	8.3%

12.2.2 Capital Cost Learning Rate Assumption and Forecast

Stakeholders were asked to provide a view on what they considered to be the main cost drivers behind capital costs. Based on stakeholder feedback and publically available literature Arup was able to determine its view on the future direction of cost and develop a learning rate forecast. For the forecast Arup primarily used views from the stakeholder survey and reputable forecast published by the IEA

(World Energy Outlook 2014)[45]. Stakeholder respondents provided limited views and opinions on how capital costs could change in the future. . After an extensive review it was concluded that no reliable reports were available, providing a robust view on the future direction of AD and AD CHP capital cost. Therefore, it was concluded that no improvement in capex cost is likely to take place.

Appendix C provides a summary of the cost index forecast for AD and AD CHP, which is assumed to be 0% by 2020 and 0% by 2030.

Table 155 AD Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	2,425	2,425	2,425	2,425
Medium	3,190	3,190	3,190	3,190
High	4,223	4,223	4,223	4,223

Table 156 AD CHP Capital Cost Forecast 2015 – 2030, 2014 Real Prices Full Condensing Basis / CHP-mode £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	3,776	3,776	3,776	3,776
Medium	4,556	4,556	4,556	4,556
High	5,615	5,615	5,615	5,615

12.3 Operating Cost

The operating costs of AD and AD CHP plant are driven mainly by the labour required to operate and maintain processing, digestion and electricity generation equipment. A summary of internal and stakeholder views of operating cost drivers is presented below. Views from stakeholders were limited and have been merged with Arup's own internal view on the drivers and direction of cost:

[45] A complete list of the references used in the report is available in Appendix I. For AD and AD CHP technology reports used for the analysis included: Green Investment Bank, the UK Anaerobic Digestion Market; DECC / DEFRA, Anaerobic Digestion Strategy and Action Plan, 2011; Anaerobic Digestion & Biogas Association, Anaerobic Digestion Roadmap, December 2012; NREL, Feasibility Study of Anaerobic Digestion of Food Waste in St. Bernhard, Louisiana, January 2013; Royal Agricultural Society of England, A Review of Anaerobic Digestion Plants on UK Farms, 2011.

- The feedstock processing requirement of food waste AD plant is labour intensive, leading to high operation cost relative to plants with installed capacities of a similar scale but using an alternative feedstock.
- The stakeholder and internal data indicated economies of scale for project capital costs. However economies of scale were not observed to be present for operating cost.

Tables 157 and 158 provide the low, medium and high operational cost ranges for the medium AD and AD CHP plant under review. It should be noted that feedstock costs are accounted for separately and not part of operating cost (please see the cost definition presented in Chapter Three). Overall a comparison of the current DECC operating cost data and the Arup 2015 update indicates a 40% reduction in operating cost for both AD and AD CHP respectively.

For LCOE modelling purposes feedstock gate fees are assumed to be an income for accepting the waste which offsets LCOE. For consistency with the Arup 2011 analysis digest disposal costs have been excluded from the LCOE analysis. Recent work by the GIB does however indicate that these costs form an important part of the lifecycle cost of an AD plant.

12.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs Arup understand that the key drivers are labour and availability of components. As outlined above stakeholder views were very limited with no stakeholders providing a view on the future direction of operating cost.

Based on available internal and external data Arup's view is that the likely direction of future operating cost should be assumed constant. With the technology now reaching an advanced stage of development and labour costs remaining the principal cost driver, it is Arup's view that no significant learning effects are expected to take place. It can therefore be stated that it is Arup's expectation that all of the possible cost reductions via learning has taken place. Table 159 and 160 present the range of current operating cost and how it can be expected to change over time.

Appendix C, provides a summary of the cost index forecast applied to AD and AD CHP. Based on an analysis of learning rates and deployment opex cost is expected to remain stable at its current level.

Table 157 AD Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	AD
Low	214
Medium	358
High	566

Table 158 AD CHP Operating Costs (Financial Close 2015), 2014 Real Prices Full Condensing / CHP-mode £'000/MW

£'000s/MW	AD CHP
Low	214
Medium	358
High	566

Table 159 AD Operating Cost Forecast 2016 – 2030, 2014 Real Prices Full Condensing Basis £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	214	214	214	214
Medium	358	358	358	358
High	566	566	566	566

Table 160 AD CHP Operating Cost Forecast 2016 – 2030, 2014 Real Prices Full Condensing Basis / CHP-mode £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	214	214	214	214
Medium	358	358	358	358
High	566	566	566	566

12.4 AD Gate Fees

Arup has collated and reviewed AD gate fee price data from stakeholders, benchmarks and published sources of information. Overall, Arup was able to collect a large sample of 17 data points. However, it should be noted that the 17 data points were collected from only three stakeholders.

Arup also reviewed alternative data sources to enhance its view of AD gate fees. Following a review of published data it was concluded that WRAP's Gate Fee Report provided a more representative and broader view of UK AD gate fees. The values used for Arup's analysis are based on information from eight commercial AD operators.

Based on WRAP's data the median gate fee reported a value of £25/tonne, with a range of 18/tonne to 35/tonne. To convert the £/tonne value to a £/MWh value Arup applied the following assumptions:

- A GCV of 16.99GJ/tonne[46];
- To convert from GJ to MWh a conversion of 3.6 is applied..

The WRAP report also provided a view on how gate fees could be expected to change over time. Overall, 58% of AD operators expect gate fees to decline over the medium-term (five years). The key factor behind this view is an expectation of increases in competition for feedstock contracts within the AD market and availability of capacity. Therefore, based on the information provided by the WRAP report it was assumed that gate fees could be expected to fall. Based on collected data stakeholders expect gate fees to potentially fall to £15/tonne (based on the lowest value in our data sample) by 2020. Arup has no evidence that gate fees will continue to fall beyond 2020 and are therefore assumed constant.

Arup has estimated a minimum, median and maximum AD gate fee price presented on table 161 below. The medium value of -£5.30/MWh can be compared to DECC's current assumption of £50.95/MWh. The data has indicated

[46] AD gate fees are based on data from WRAP's Gate Fees report (low, medium and high) and an assumed GCV of 16.99GJ/tonne.

a significant fall driven mainly by increased competition and availability of the plant. Table 161 provides a summary of the estimated gate fee prices expected to be paid for by operators.

For LCOE modelling purposes it is important to note that gate fees are treated as an income with LCOE presented net of the discounted revenue received.

Table 161 AD Gate Fee Assumptions Forecast 2015 – 2030, 2014 Real Prices £/MWh

£/MWh	2015	2020	2025	2030
Low	-7.42	-3.18	-3.18	-3.18
Medium	-5.30	-3.18	-3.18	-3.18
High	-3.81	-3.18	-3.18	-3.18

12.5 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these to existing DECC assumptions. The objectives of the analysis was to identify where cost had changed and understand what is driving the observed change. Tables 162 and 163 provides current cost estimates for 2015, the DECC comparator and overall percentage change.

The number of data points captured for the analysis is relatively small. Therefore, a comparison between DECC's existing assumptions and the Arup 2015 figures will not be exact.

It should be noted that the cost data collected is for AD and AD CHP plants which have reached final commissioning or are currently under development. Arup has prepared two estimates for AD and AD CHP cost. Arup has used DECC's current cost estimates and compared these with those generated by the analysis. New and old cost estimates for: pre-development, construction; infrastructure; and operating cost are presented below on tables 162 and 163. The following provides Arup's view on what has caused the change in cost:

- **Pre-development cost:** for AD pre-development, cost is reported to have decreased by **78%** between the current DECC assumptions and the figure generated by the 2015 Update. The change is understood to be driven by improvements in designing sites, deployment experience and improved efficiency in obtaining planning and environmental permitting. Overall, based on the data collected from internal stakeholder and external sources cost is reported to have halved.

- **Construction cost:** a comparison of the DECC assumptions and the Arup 2015 update indicates a small decrease in construction cost for AD **(31%)** and a large decrease for AD CHP **(4%)**. AD is a well-known technology with costs not expected to change significantly going forward. Based on the available data and knowledge of AD construction costs, it was determined that there is little scope for further cost reductions. Therefore for the forecast it was assumed that the construction cost for AD plant will remain constant.
- **Operating cost:** cost is understood to be driven by labour (which is expected to rise but less than the rate of inflation), the price of chemicals and the disposal of waste. The comparison indicates that cost has decreased significantly by at close to **40%** for both AD and AD CHP. The fall is cost is understood to be driven mainly by a better understanding of the technology and its lifecycle. In addition, since the 2011 Study deployment of AD and AD CHP technology has increased significantly, driving learning effects and improvements around operating plant.
- It should be noted that no UoS cost data was available from internal or external sources. Therefore, Arup has use the UoS cost estimate from biomass CHP.

Table 162 AD Cost Comparison between Arup 2015 and DECC Current, 2014 Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	40	40	40	40
	Construction	£/kW	2,851	2,851	2,851	2,851
	Infrastructure	£'000	727	727	727	727
	Total capex	**£/kW**	**3,190**	**3,190**	**3,190**	**3,190**
	Total opex	**£MW**	**358,002**	**358,002**	**358,002**	**358,002**
	Fixed O&M	£/MW	272,116	272,116	272,116	272,116
	Variable O&M	£/MWh	4.1	4.1	4.1	4.1
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	31,407	31,407	31,407	31,407
	UoS	£/MW	12,921	12,921	12,921	12,921

	Assumption	Unit	2015	2020	2025	2030
DECC Current	Pre-development	£/kW	184	184	184	184
	Construction	£/kW	4,120	3,989	3,932	3,887
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**4,304**	**4,173**	**4,116**	**4,071**
	Total opex	**£/MW**	**618,828**	**620,660**	**622,497**	**624,340**
	Fixed O&M	£/MW	312,088	313,025	313,965	314,908
	Variable O&M	£/MWh	32.3	32.4	32.5	32.6
	Insurance	£/MW	60,265	60,446	60,628	60,810
	UoS	£/MW	8,969	8,969	8,969	8,969
% Change	Pre-development	%	-78%	-78%	-78%	-78%
	Construction	%	-31%	-29%	-27%	-27%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-26%**	**-24%**	**-23%**	**-22%**
	Total opex	%	**-42%**	**-42%**	**-42%**	**-43%**

Table 163 AD CHP Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices Full Condensing Basis / CHP-mode

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	40	40	40	40
	Construction	£/kW	4,138	4,138	4,138	4,138
	Infrastructure	£'000	727	727	727	727
	Total capex	**£/kW**	**4,556**	**4,556**	**4,556**	**4,556**
	Total opex	**£MW**	**358,002**	**358,002**	**358,002**	**358,002**
	Fixed O&M	£/MW	272,116	272,116	272,116	272,116
	Variable O&M	£/MWh	4.1	4.1	4.1	4.1
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	31,407	31,407	31,407	31,407
	UoS	£/MW	12,921	12,921	12,921	12,921
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	4,330	4,192	4,133	4,085
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**4,330**	**4,192**	**4,133**	**4,085**
	Total opex	**£/MW**	**606,043**	**607,836**	**609,635**	**611,439**
	Fixed O&M	£/MW	378,194	379,330	380,469	381,612
	Variable O&M	£/MWh	21.5	21.6	21.7	21.7
	Insurance	£/MW	60,339	60,520	60,702	60,884
	UoS	£/MW	8,980	8,980	8,980	8,980
	Pre-development	%	-	-	-	-

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	-4%	-1%	0%	1%
	Infrastructure	%	-	-	-	-
	Total capex	%	**5%**	**9%**	**10%**	**12%**
	Total opex	%	**-41%**	**-41%**	**-41%**	**-41%**

12.6 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC's current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net Power:** the average plant size is reported to have changed marginally in scale from 2.3MW to 2.4MW and 2.3MW to 1.9MW for AD and AD CHP respectively. The small change reflects the current scales that AD plants are being deployed at and the increased certainty from developers over the scale of plant. A decrease in the average installed capacity is also reflected in the GIB's recent report on the state of the AD market. In 2013 the average installed capacity of an AD plant under the RO was reported to be around 2.0MW, since then installed capacity has reduced to 1.6MW.
- Steam output was also noted as decreasing marginally between DECC's current and Arup's 2015 updated figure 1.9MWth to 1.8MWth.
- **LHV efficiency:** compared to existing DECC assumptions the 2015 Update shows a marginal increase in LHV electrical efficiency from 36.5% to 40.2% for AD and marginal decrease from 36.5% to 32.0% for AD CHP. The change in LHV efficiency is expected to reduce AD LCOE but increase AD CHP LCOE
- **Availability:** plant availability data was reported by stakeholders but no load factor information provided. Arup reviewed and interpreted the availability data as equivalent to the net load factor i.e. the maximum time proportion a plant will generate in a year. For the purposes of the analysis it was assumed that availability is the same as 'load factor', defined under Section Three. For modelling purposes only availability was set at 100%.
- **Load factor:** the net load factor figure assumed in this study of 79% falls within Arup's expected range for AD projects and reflects how developers have continued to understand the lifecycle and operation of plant. It should be noted that when compared to the DUKES load factor figure of 60% (average of last five years) the current DECC and Arup estimates are both significantly

higher. The increase in load factor reflects increased deployment of AD plant, learning rate effects and developers' better understanding of AD plant operation. A recent AD market study produced by the GIB also suggests an upward trend in load factor. For example, in 2015 the 'upper quartile' load factor is 91%, increasing from 80% last reported by the GIB in 2013. A summary of the load factors used for the analysis are provided in **Appendix B.**

Table 164 AD Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	2.32	2.43	0.11
Net LHV efficiency	%	37%	40%	10.1%
Availability	%	90%	100%	10.7%
Load factor (gross)	%	93%	79%	-15.0%
Load factor (net)	%	84%	79%	-5.8%

Table 165 AD CHP Technical Assumptions Full Condensing Basis / CHP-mode

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	2.32	1.93	-0.39
Average steam output	MWth	1.86	1.79	-0.07
Net LHV efficiency	%	37%	32%	-12.3%
Availability	%	90%	100%	10.7%
Load factor (gross)	%	93%	79.1%	-15.0%
Load factor (net)	%	84%	79%	-5.8%

The assumed load factors for AD and AD CHP are presented below on Table 166. The assumed technical asset lifetime for both forms of AD is 20 years.

Table 166 Assumed Load Factor %

%	AD	AD CHP
Medium	79.1%	79.1%
Medium	79.1%	79.1%

12.7 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup has calculated LCOE for the AD and AD CHP reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC’s hurdle rates. Tables 169 to 170 provide the LCOE results based on DECC’s updated hurdle rate for the technology.

Table 167 AD LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	91	91	91	91
Medium	105	105	105	105
High	125	125	125	125

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 168 AD CHP LCOE 2016 – 2030, 2014 Real Prices, Full Condensing Basis / CHP-mode* £/MWh

£/MWh	2016	2020	2025	2030
Low	93	91	86	85
Medium	109	107	102	101
High	131	128	124	122

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 169 LCOE 2016 – 2030 (Anaerobic Digestion), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	85	86	86	86
Medium	99	99	99	99
High	116	117	117	117

Table 170 LCOE 2016 – 2030 (Anaerobic Digestion CHP), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	89	88	83	82
Medium	104	103	99	97
High	125	124	120	118

12.8 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between the LCOEs based on Arup's new cost data, DECC's current assumptions and discount rates. A summary of all the LCOEs generated using DECC's current and new hurdle rates are presented in **Appendix I.**

Analysis of the underlying cost data indicates that for both AD and AD CHP there has been reasonably large decreases in construction and operating cost which has led to a reduction in AD and AD CHP LCOE. The fall in both construction and operating costs reflect large-scale improvements within the supply chain for AD project delivery (construction, EPC), availability of competitive O&M services and operator learning effects allowing optimisation of the project lifecycle. In addition, it is worth noting that there has been a large increase in deployment which is the main reason for the large fall in cost.

For AD and AD CHP the data indicate that a project starting in 2016 and commissioning by 2020 is expected to have an LCOE which is 30%/34% and 21%/27% less than current DECC figures respectively. For comparison purposes the current DECC figures have been inflated from 2012 to 2014 prices. Key cost and technical drivers for AD include a decrease in capital cost, operating cost and an increase in load factors.

Arup has reviewed WRAP's Bio-methane report which contains benchmark cost and levelised cost information. The central LCOE figure produced by WRAP's report is £152/MWh and significantly different from Arup's medium LCOE figure of £105/MWh. Following a review of the costs included within WRAP's LCOE figure, it was assessed that WRAP had included the same cost categories as the 2015 Update with the exception of digest disposal costs. Arup understand that the inclusion of digest disposal costs accounts for the main difference between the LCOE results produced. For consistency with the 2011 Study Arup did not include waste disposal costs as part of the analysis. Arup is however aware that digest disposal costs do form a significant part of the lifecycle cost of an AD plant. Therefore, the costs presented in this chapter should be interpreted with caution.

Table 171 AD Comparison Arup vs. DECC, 2014 Real Prices £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	91	91	106	117	-15.0%	-22.2%
Medium	105	105	150	160	-29.8%	-34.0%
High	125	125	218	227	-42.6%	-44.8%

Table 172 AD CHP Comparison Arup vs. DECC, 2014 Real Prices Full Condensing / CHP-mode £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	93	91	91	101	1.8%	-10.5%
Medium	109	107	138	147	-20.9%	-27.3%
High	131	128	198	205	-33.8%	-37.5%

13 Landfill Gas

13.1 Introduction

Landfill Gas ('LFG') electricity generation is a mature, commonly used technology, with a wide range of developers and suppliers. Most sites have historically used gas reciprocating engines that are typically operated on low calorific gas. The internal and external benchmark data collected indicated that plants range in scale from 0.4MW to 4.6MW range. The average installed capacity has been estimated to be 2.1MW. Following internal and external discussions the market for LFG development is understood to be mature with few (if any) sites likely to be developed in the future.

LFG projects have seen an overall decline in gas resource as various forms of waste have been diverted from landfill to incineration and anaerobic digestion. The trend is likely to continue as a result of competing technologies for waste, increases in landfill tax and targets for reducing the quantity of waste sent of landfill.

It is understood that as a result of current market conditions any new capacity is likely to only replace existing i.e. as gas reserves on a particular site decline installed capacity is likely to reduce. Between 2010 and 2015 installed capacity increased marginally from 1,009MW to 1,051MW. For the analysis Arup produced cost and technical estimates for one category:

- Landfill gas

The assumed operational life for a landfill gas generators is assumed to be 28 years.

13.2 Data Collection

Following the process outlined in Section 2 Arup contacted a range of landfill gas stakeholders but received no data. Therefore, it should be noted that all of the cost and technical estimates produced here are based on internal and external benchmarks only. Arup was able to generate over 20 data points for use in the LCOE analysis.

Based on the data collection criteria outlined in Section 2 all the data points were assessed to be robust, representative and useful to the analysis. All results produced during the analysis were compared with the historic data and tested against internal knowledge. Both the Arup 2011 and 2015 Update data were assessed to be comparable.

In terms of installed capacity Arup has collected benchmark data which represents installed capacity of 55.1MW and an average installed capacity of 2.1MW. Following the data analysis and validation process the low and high installed capacity for landfill gas was 0.4MW to 4.6MW respectively.

13.2.1 Capital Expenditure

Pre-development costs were estimated to vary between £0.02m/MW to £0.06m/MW with a medium cost of £0.04m/MW. Construction costs for LFG projects are based on internal project data and were assessed to range from £0.8m/MW to £3.6m/MW and a medium cost of £2.2m/MW. The main construction cost expenditure is for gas collection, processing and generation equipment. Unit costs illustrate a reasonably large variance indicating that there is potentially wide range in the scale of plant delivered and installed at sites. Other infrastructure costs represent around additional £0.34m/MW. By combining the pre-development, construction and infrastructure costs total medium capital costs are equal to £2.6m/MW.

Table 173 Landfill Gas Capital Costs (2015 Financial Close), 2014 Real Prices £'000/MW

£'000/MW	Landfill Gas
Low	1,066
Medium	2,572
High	4,108

Table 174 Landfill Gas Capital Cost Breakdown for a Medium Project %

Capital cost item	Landfill Gas
Pre-development	1.5%
Construction	85.1%
Infrastructure	13.3%

13.2.2 Capital Cost Learning Rate Assumption and Forecast

The stakeholder survey asked for views on what was considered to be the main cost drivers behind pre-development and construction cost. Unfortunately no external views were received from stakeholders, therefore Arup relied on internal and external literature to support its cost forecast. Following an internal and external review it was concluded that no further improvement in construction cost was expected to take place. Arup's view is that the technology is mature with little scope for further technical or cost improvement. **Appendix C**, provides a summary of the cost index forecast for landfill gas and applied in the levelised cost modelling.

Table 175 Landfill Gas Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	1,066	1,066	1,066	1,066
Medium	2,572	2,572	2,572	2,572
High	4,108	4,108	4,108	4,108

13.3 Operating Cost

The estimated range of operating cost is relatively wide between the medium, low and high. It is understood that differences in waste composition at sites can impact on total O&M cost. For example contaminates within gas can increase wear in generation equipment, resulting in lower efficiency and increased plant maintenance. Table 176 presents the operational cost ranges calculated

13.3.1 Operating Cost Learning Rate Assumption and Forecast

Operation and maintenance of the gas collection and generation equipment is the main driver of current operating costs. After an internal review no learning effects are anticipated due to maturity of the technology and high-level of operational experience within the industry. Table 177 indicates the range of current operational costs and how they are expected to remain constant over time.

Appendix C, provides a summary of the cost index forecast applied to landfill gas.

Table 176 Landfill Gas Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	Landfill Gas
Low	79
Medium	135
High	169

Table 177 Landfill Gas Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	79	79	79	79
Medium	135	135	135	135
High	169	169	169	169

13.4 Cost Breakdown

Based on the internal and external benchmark data Arup was able to generate a new set of cost figures and compare these to existing DECC assumptions. The objective of the analysis was to identify where costs have changed and the key drivers of that change. Table 176 provide current costs estimates for 2015, the DECC assumptions comparator and percentage change.

For the comparison Arup has compared DECC's current costs against those from the 2015 Update. New and old cost estimates for pre-development, construction, and operating cost are presented below. The following provides Arup's view on what has caused the change in cost:

- **Pre-development cost:** for LFG pre-development costs are reported to have decreased between the current DECC assumptions and the 2015 Update figures. Cost is understood to have fallen significantly **(>50%)** as a result of improvements in designing sites, experience and improved efficiency in obtaining successful planning and environmental permitting. It should be noted that the pre-development cost presented here is based on internal data only. Therefore, deriving a direct comparison between the DECC and 2015 Update is not exact.

- **Construction cost:** a comparison of the DECC and 2015 Update cost figures indicates a marginal change of around **3%**. LFG is a well-established technology with costs not expected to change significantly going forward. Based on available data and knowledge of the LFG technology, construction costs are well known with little scope for any improvement in cost.
- **Operating cost:** cost is understood to be driven by O&M of the gas collection and generation equipment. Overall the comparison indicates that costs have increased but are close to the internal benchmark.

Table 178 Landfill Gas Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	40	40	40	40
	Construction	£/kW	2,189	2,189	2,189	2,189
	Infrastructure	£'000	727	727	727	727
	Total capex	**£/kW**	**2,572**	**2,572**	**2,572**	**2,572**
	Total opex	**£MW**	**134,735**	**134,735**	**134,735**	**134,735**
	Fixed O&M	£/MW	81,016	81,016	81,016	81,016
	Variable O&M	£/MWh	9.0	9.0	9.0	9.0
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	1,620	1,620	1,620	1,620
	UoS	£/MW	6,481	6,481	6,481	6,481
DECC Current	Pre-development	£/kW	130	130	130	130
	Construction	£/kW	2,115	2,094	2,086	2,080
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**2,245**	**2,224**	**2,216**	**2,210**
	Total opex	**£/MW**	**115,205**	**115,480**	**115,756**	**115,977**

	Assumption	Unit	2015	2020	2025	2030
	Fixed O&M	£/MW	61,858	62,013	62,168	62,293
	Variable O&M	£/MWh	9.4	9.4	9.4	9.4
	Insurance	£/MW	1,362	1,366	1,369	1,372
	UoS	£/MW	5,282	5,282	5,282	5,282
% Change	Pre-development	%	-69%	-69%	-69%	-69%
	Construction	%	3%	5%	5%	5%
	Infrastructure	%	-	-	-	-
	Total capex	**%**	**15%**	**16%**	**16%**	**16%**
	Total opex	**%**	**17%**	**17%**	**16%**	**16%**

Arup reviewed the estimates it produced against benchmark cost data from published sources. The objective here was to provide validation of the findings and provide confidence around the observations. To understand the change in cost Arup collected development, construction and opex benchmark data. Overall the following was observed and compared to the 2015 Updates:

- **Construction costs:** comparator data was available from WEC which estimated the range of cost to be £1,287/kW and £1,321/kW. The 2015 Update estimate of £2,189/kW is higher than the benchmark cost. However, the values generated by the 2015 Update dataset conforms with Arup's expectations i.e. there has been little or no change in cost between the 2011 Study and 2015 Update. Arup validated the construction cost internally and is comfortable with its use for LCOE modelling purposes.
- **Operating cost**: data was available from WEC which indicated fixed O&M cost to be range from £96k/MW to £76k/MW. Arup's 2015 update of £81k/MW is above DECC's current estimate but sits between the values collected externally. It was concluded that the operating cost value produced by the dataset was potentially high but close to the observed benchmarks.

13.5 Technical Assumptions

Based on the collected data Arup was able to carry out a comparison between DECC's current LCOE technical assumptions and the 2015 Update. The following provides a summary of the observations made:

- **Net Power:** the overall scale of plant has increased from 1.2MW to 2.1MW. It is understood that there is a lack of commercial development opportunities for new LFG projects, with stakeholders focussed mainly on managing capacity at sites.
- **Availability:** plant availability data was reported by stakeholders but no load factor information provided. Arup reviewed and interpreted the availability data as equivalent to the net load factor i.e. the maximum time proportion a plant will generate in a year. For the purposes of the analysis it was assumed that availability is the same as 'load factor', defined under Section Three. For modelling purposes only availability was set at 100%.
- **Load factors:** for LFG internal data indicated a large increase in load factor from 57% to 90%. The internal data was assessed to be not representative. Following a review of load factor data from the OFGEM RO register, the data collected was assumed to be representative; based on real load factor performance data. The assumed load factor is 58% which is marginally higher than DECC's current estimate of 57% and the same as the average value reported by DUKES. A summary of the load factors used for the analysis are provided in **Appendix B.**

Table 179 Landfill Gas Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	1.20	2.12	0.92
Availability	%	100%	100%	0.0%
Load factor (gross)	%	57%	58%	1.8%
Load factor (net)	%	57%	58%	1.8%

The assumed load factors is presented below on table 180 and an assumed installation lifetime of 28 years.

Table 180 Assumed Load Factor %

%	Landfill Gas
Medium, gross	58.1%
Medium, net	58.1%

13.6 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for the LFG reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates Table 182 provides the LCOE results based on DECC's updated hurdle rate for the technology.

The LCOE modelling load factor was based only on data collected via the OFGEM RO register and is assumed to be held constant for the forecast period. This assumption was made due to limited information and published views.

Table 181 Landfill Gas LCOE 2016 – 2030, 2014 Real Prices* £/MWh[47]

£/MWh	2016	2020	2025	2030
Low	40	40	40	40
Medium	60	60	60	59
High	80	80	80	79

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

[47] Please note that all costs and technical inputs are assumed to remain constant between 2016 and 2030. The decrease in LCOE between 2025 and 2030 is a result of a fall in discount rate (e.g. 2028 (5.4%), 2029 (5.1%) and 2030 (4.8%).

Table 182 LCOE 2016 – 2030 (Landfill Gas), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	43	43	43	43
Medium	67	67	67	67
High	91	91	91	91

13.7 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup's new cost data, DECC's current assumptions and discount rates. Overall, for LFG data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE 17% less than current DECC figures. A summary of all the LCOE generated using DECC's current and new hurdle rates is presented in **Appendix I.**

For comparison purposes the current DECC figures have been inflated from 2012 to 2014 prices. Key cost and technical drivers for landfill gas include a marginal increase in capital and a small decrease in operating costs. The main cost drivers of LCOE have remained broadly similar reflecting the relative maturity of the technology and that the asset lifecycle is already well known and reflects our internal expectations. The WEC reports that fixed operating costs should range between 75k/MW and 95k/MW, Arup's estimated cost sits between these two figures at £81k/MW providing comfort around the final value.

Table 183 Landfill Gas Comparison Arup vs. DECC, 2014 Real Prices £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	40	40	47	47	-14.4%	-14.4%
Medium	60	60	72	72	-16.9%	-16.9%
High	80	80	104	104	-23.1%	-23.1%

14 Sewage Gas

14.1 Introduction

Sewage gas is the biological degradation of putrescible material in the absence of oxygen, resulting in a reduction in the quantity of solid material and the production of biogas, consisting of approximately 55-70% methane, 30-45% carbon dioxide and 1% nitrogen. The process operates under mesophilic (approximately 36°C) or thermophilic (approximately 55°C) conditions.

The process is widely employed in the water industry for the stabilisation of sewage sludge to reduce the quantity of material going to disposal, to improve its aesthetic nature before it is recycled and to generate useful energy. At larger plants where it is economic biogas is collected and used to generate heat and electricity via CHP.

DUKES indicates that between 2010 and 2014 there was a net increase of 15MW of new capacity from 193MW to 208MW. Sewage gas installations are usually installed as part of a treatment process and are reasonably bespoke to the site and location it is being installed at. The number of sewage gas installations is generally limited by the availability of sewage supply.

14.2 Data Collection

For the data collection process Arup contacted projects developers, water and utility companies. Overall a limited dataset was collected from two developers (both water companies), yielding four project data points.

Based on the data collection criteria outlined in Chapter Three, three data points were assessed to be robust and useful to the analysis. Two data points represented ‘advanced’ and one ‘conventional’ sewage gas plant. During the 2010 Study the dataset was evenly split between conventional and advanced, with three data points each. To generate a comparable set of data Arup applied weightings to the available data to generate a comparable set of costs. The overall data set was quite small but assessed to be representative. Total installed capacity is 7.2MW with an average of 2.4MW per projects.

14.2.1 Capital Expenditure

Capital expenditure on a unit cost will vary depending on the actual process which is deployed i.e. conventional or advanced sewage gas projects. For conventional plants, the main cost item is the generation equipment. Advanced forms of sewage gas plant also include additional equipment which treats waste prior to the digestion process. Table 184 presents the capital cost ranges for sewage gas based on the combined dataset.

The main drivers of construction cost include the cost of labour, importing generation and process equipment. The technology which is used in conventional sewage gas generation is mature and has been extensively deployed. Table 186 provides Arup’s forecast of Sewage gas construction cost.

Following an extensive literature review there was no indication that any future learning can be expected to take place within the technology. The sewage gas stakeholders contacted provided no view on the future direction of cost. With only a limited number of sewage gas projects planned for deployment in the UK, it was concluded that the capex and opex adjustment factors for sewage gas should remain constant for LCOE modelling purposes.

Table 184 Sewage Gas Capital Costs (2015 Financial Close), 2014 Real Prices £’000/MW

£’000/MW	Sewage Gas
Low	2,256
Medium	5,551
High	7,493

Table 185 Sewage Gas Capital Cost Breakdown for a Medium Project %

Capital cost item	Sewage Gas
Pre-development	7.5%
Construction	91.6%
Infrastructure	0.9%

14.2.2 Capital Cost Learning Rate Assumption and Forecast

Stakeholders were asked to provide a view on what they considered to be the main cost drivers behind pre-development and construction costs. Unfortunately Arup did not receive any feedback and a subsequent review of industry and market literature did not ascertain a view. Therefore, due to a lack of evidence and an understanding that the technology is already mature, Arup has therefore assumed a constant learning rate for the forecast.

Appendix C, provides a summary of the cost index forecast sewage gas. Based on an analysis of learning rates and deployment the reduction in cost is assumed to be 0% by 2020 and 0% by 2030.

Table 186 Sewage Gas Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	2,256	2,256	2,256	2,256
Medium	5,551	5,551	5,551	5,551
High	7,493	7,493	7,493	7,493

14.3 Operating Cost

Operating costs for conventional sewage gas plant are primarily focussed on handling and maintaining the generation equipment. Labour and the cost of imported spare parts are also known to be key drivers. For advanced plant additional labour is required to operate the pre-treatment equipment. Table 187 below presents the operating cost range for sewage gas projects. Overall for the UK the cost ranges from £94k/MW to £211k/MW with a medium cost of 148k/MW.

14.3.1 Operating Cost Learning Rate Assumption and Forecast

Arup has carried out an extensive review of industry literature and found no reliable view on the future direction of operating cost. After an internal review no learning effects are anticipated due to the maturity of the technology and the high-level of operational experience within the industry. Table 188 indicates the range of current operational costs.

Appendix C, provides a summary of the cost index forecast applied to sewage gas.

Table 187 Sewage Gas Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	Sewage Gas
Low	94
Medium	148
High	211

Table 188 Sewage Gas Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	94	94	94	94
Medium	148	148	148	148
High	211	211	211	211

14.4 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these with existing DECC assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Table 189 below provides current cost estimates for 2015, DECC assumptions comparator and the overall percentage change.

New and old cost estimates for pre-development, construction and operating cost is presented below. The following provides Arup's view on what has caused the change in cost:

- **Pre-development cost:** stakeholders have provided cost data. However the current DECC dataset does not include a value for pre-development cost, comparing the current and new costs is therefore not possible. It should be noted that sewage gas installation cost will be bespoke to the sewage plant where it is installed. Despite the small size of the data sample the costs were considered to be representative.
- **Construction cost:** a comparison of DECC's and the 2015 Update data indicated a 36% increase in construction cost. Challenges around standardising delivery of the technology appear to remain. The construction costs generated here should be interpreted with a degree of caution, since the overall scale of the dataset is small.
- **Operating cost:** Arup understand that the key costs driving operating costs include labour, parts and replacement. Importantly, the data currently indicates an increase in cost from £113k/MWa to £148k/MWa. It should be noted that the analysis included cost items which had not been previously reported including variable O&M, insurance and UoS cost.

Table 189 Sewage Gas Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	416	416	416	416
	Construction	£/kW	5,085	5,085	5,085	5,085
	Infrastructure	£'000	171	171	171	171
	Total capex	**£/kW**	**5,551**	**5,551**	**5,551**	**5,551**
	Total opex	**£MW**	**148,232**	**148,232**	**148,232**	**148,232**
	Fixed O&M	£/MW	48,584	48,584	48,584	48,584
	Variable O&M	£/MWh	10.5	10.5	10.5	10.5
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	36,569	36,569	36,569	36,569
	UoS	£/MW	12,921	12,921	12,921	12,921
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	3,738	3,637	3,594	3,560
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**3,738**	**3,637**	**3,594**	**3,560**
	Total opex	**£/MW**	**113,416**	**113,729**	**114,044**	**114,296**
	Fixed O&M	£/MW	104,447	104,761	105,076	105,328
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	8,968	8,968	8,968	8,968
	Pre-development	%	-	-	-	-

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	36%	40%	41%	43%
	Infrastructure	%	-	-	-	-
	Total capex	%	**49%**	**53%**	**54%**	**56%**
	Total opex	%	**31%**	**30%**	**30%**	**30%**

14.5 Technical Assumptions

Based on the internal benchmarks Arup carried out a comparison between the 2015 Update and DECC's current LCOE assumptions. The following provides a summary of the observations made.

- **Net power:** overall the scale of the average plant is reported to have increased from 1.6MW to 3.4MW. The increase in scale reflects the potential scale of future projects.
- **Availability:** data was available from stakeholders and external sources. Overall, sewage gas availability has reduced when existing DECC assumptions are compared with those produced by the latest analysis; 100% to 90%. It should be noted that the existing assumption of 100% is only required for LCOE modelling purposes and assumes that the existing load factor is net of availability. The new Arup availability assumptions of 90% has been included within the net load factor assumption.
- **Load factor:** the data indicated an increase in load factor which is expected to reduce the LCOE. The central load factor calculated is 51.3% which has increased from 44.0%. A summary of the load factors used for the analysis are provided in **Appendix B**

Table 190 Sewage Gas Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	1.60	3.42	1.82
Availability	%	100%	90%	-10.3%
Load factor (gross)	%	44%	51%	16.6%
Load factor (net)	%	44%	46%	4.5%

The assumed load factor is presented below on Table 191, the assumed installation lifetime is 20 years.

Table 191 Assumed Load Factor %

%	Sewage Gas
Medium, gross	51.3%
Medium, net	46.0%

The LCOE modelling load factor was based only on data collected internally and from benchmarks. The load factor is assumed to be held constant with no change going forward.

The latest estimate of load factor of 51% has been validated against DUKES data with the last five year average also being 51%. A summary of the load factors used for the analysis are provided in **Appendix B**

14.6 Levelised Cost

Based on the learning rate forecast, capital and operating cost profiles Arup calculated LCOE for a sewage gas reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Table 193 provides the LCOE results based on DECC's updated hurdle rate for the technology.

Table 192 Sewage Gas LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	94	94	94	94
Medium	176	176	176	176
High	225	225	225	225

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 193 LCOE 2016 – 2030 (Sewage Gas), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	100	100	100	100
Medium	191	191	191	191
High	244	244	244	244

14.7 Comparison of DECC and Arup LCOE Values

The following summary table provide a comparison between LCOE based on Arup’s new cost data, DECC’s current assumptions and discount rates. A summary of all the LCOEs generated using DECC’s current and new hurdle rates is presented in **Appendix I.**

Overall, at the UK level the data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE which is around 56%/57% higher than DECC current estimate.

Table 194 Sewage Gas Comparison Arup vs. DECC 2014 Real Prices £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	94	94	82	82	14.5%	15.0%
Medium	176	176	113	112	56.1%	57.0%
High	225	225	166	165	35.5%	36.3%

15 Tidal Stream

15.1 Introduction

For the Study Arup has collected data on two marine technologies. These are tidal stream and wave. Tidal stream devices extract energy from water flows generated by variation in the sea level caused by tides, extracting potential energy generated by the change in height from a high to low tide. Tidal current are created through the movement of the tides. Tidal current energy is the extraction of energy from the tidal flow.

The UK continues to be a leader in the development of tidal stream technology. According to the Ocean Energy Systems ('OES') Annual Report by 2014 the UK had installed capacity of 5.6MW and approximately 96MW of projects consented. To facilitate deployment in 2012 DECC launched the Marine Energy Array Demonstrator ('MEAD') to support the development and testing of pre-commercial marine devices in an array formation at sea. Two companies that received support include MeyGen Ltd and SeaGeneration. MeyGen Ltd is currently on course to install their first turbine in spring 2016.

The Study aimed to collect data on 'deep' and 'shallow' tidal schemes. Following a review of the data collected from stakeholders, internal sources, reports and benchmarks Arup was only able to develop cost estimates.

Based on the data collected it is Arup's view that tidal stream technology should continue to be considered as a FOAK technology. The current data set reflects increasing certainty around the costs of installation, lifecycle and operating life. It should be noted that the inferences and conclusions are drawn from a small data set.

The data indicates that there has been a 30% increase in construction cost relative to the current DECC LCOE cost assumption; expected a 50% decline in construction cost between 2010 and 2015 (£4.0m/MW). If DECC's cost reduction assumption is removed and only cost inflation is taken is into account (£8.1m/MW), there would is an overall decrease in cost of around 35% (£5.2m/MW). Importantly, the analysis has concluded that construction cost reductions have taken place but not at the expected rate. The reason for the reduction can be attributed to slower development of the technology.

15.2 Data Collection

Data was collected from public, internal and stakeholder sources. For the data collection process Arup primarily focussed on contacting project developers, utility companies and trade associations. Overall Arup received very little and limited individual project data. Arup collected six data points of cost and operational data including cost benchmarks and technical assumptions.

Based on the data collection criteria outlined in Chapter Three, the six available data points were assessed to be robust, representative and useful to the analysis.

An initial observation indicated that planned projects are at a significantly smaller scale than previously by DECC.

Although the overall data set was quite small it was assessed to be representative for current tidal stream development projects. All results produced by the analysis were compared against the original stakeholder data and collated benchmarks.

In terms of installed capacity the six data points collected represented 106MW, with an average installed capacity of 17.7MW of projects at various stages of development.

15.2.1 Capital Expenditure

This section provides a summary of the cost assumptions generated for tidal stream generation. The focus is to understand which key parameters have driven levelised cost, capital expenditure and operating cost. During the 2011 Arup study there was expectation that capital expenditure would reduce signifying a move from demonstration projects to full commercialisation.

The following cost and technical information for tidal stream is based primarily on data from internal and external benchmark sources with only two data points provided by stakeholders. Capital expenditure for tidal stream projects is based on six validated data points. The main capital expenditure items for tidal stream projects are related to the cost for structures, foundations and moorings.

Pre-development cost can vary significantly £0.04m/MW to £0.27m/MW and a medium cost of 0.13m/MW. The current estimate for construction cost ranges between £3.0m/MW and £7.4m/MW, with a medium cost of £5.2m/MW. The wide range in cost is partly attributed to uncertainty around project cost, installation and construction risk. The main driver for future reductions is anticipated to result from increased levels of deployment.

Table 195 below present capital cost ranges for tidal stream. The capital cost includes pre-development, construction and infrastructure. Analysis indicates that the majority of capital cost relate to construction, generation equipment and installation. The cost of labour, steel, concrete are also principal drivers of cost.

For the first time Arup has also been able to separate infrastructure cost which is assumed to include grid connection, transformer, sub-station and electrical infrastructure.

Table 195 Tidal Stream Capital Costs (2015 Financial Close), 2014 Real Prices £'000/MW

£'000/MW	Tidal Stream
Low	3,259
Medium	5,750
High	8,267

Table 196 Tidal Stream Capital Cost Breakdown for a Medium Project %

Capital cost item	Tidal Stream
Pre-development	2.2%
Construction	90.5%
Infrastructure	7.3%

15.2.2 Capital Cost Learning Rate Assumption and Forecast

Stakeholders were asked to provide a view on what they considered to be the main cost drivers behind pre-development and construction cost. Based on feedback and publically available literature an Arup view on the future direction of cost was prepared and developed into a learning rate forecast. Arup's approach involved developing a forecast split by component with turbine costs linked to global deployment of the technology. Different construction components are linked to either global or UK deployment. For the UK deployment is estimated to increase from 53MW in 2020 to 377MW in 2030. At the global level deployment is estimated to be 1,000MW by 2020 and 6,000MW by 2030

There is a wide literature analysing the potential for tidal stream in the UK. Based on limited stakeholder engagement Arup has also been able to capture developer expectations for future change in cost.

For the analysis Arup has been able to breakdown capex into two primary components which are construction cost and grid connection cost. A learning rate factor has been developed based on our internal and external research and applied to both cost components identified. For modelling purposes and consistency with previous work, Arup's learning rate forecast has been applied to only construction costs. Pre-development and infrastructure costs are assumed to be constant.

There is expected to be continued downward pressure on construction cost. **Appendix C**, provides a summary of the cost index forecast for tidal stream development. Based on an analysis of learning rates and deployment the reduction in cost is expected to be 9.7% by 2020, 24.9% by 2025 and 41.2% by 2030, which is equal to an annual reduction of -3.5%. The learning rate forecast uses a deployment rate forecast from RenewableUK and IEA to generate the expected change. However, due to the FOAK nature of the technology there is a degree of uncertainty around potential future cost reductions. The LCOE estimates must therefore be viewed with a degree of caution.

The learning rates has been estimated based on data from RenewableUK reports, stakeholders, the IEA and a UK focussed literature review. To obtain our rate 380MW of tidal stream is expected to be deployed by 2030.

Table 197 Tidal Stream Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	3,259	2,969	2,518	2,032
Medium	5,750	5,243	4,455	3,605
High	8,267	7,545	6,424	5,214

15.3 Operating Cost

Operating costs have been estimated for tidal stream which comprise of fixed and variable O&M, UoS charges and insurance. The following table illustrates the variation in cost based on the data collected. The operating costs vary quite significantly which is understood to be driven by local conditions such as availability of specialist labour, local grid charges, price and availability of components. In addition with the technology at an early stage of development lifecycle is to a degree still uncertain but expected to become more accurate as more projects are delivered.

Table 198 below provides an indication of the variation in operating cost estimated. Overall operating cost exhibits a wide range from £160k/MW to £301k/MW, with an average cost of £235k/MW. The current high cost were assumed to be reflective of the current market, which only has a limited number of suppliers that can provide appropriate O&M services.

Table 198 Tidal Stream Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	Tidal Stream
Low	160
Medium	235
High	301

15.3.1 Operating Cost Learning Rate Assumption and Forecast

The cost of offshore installation, vessel and turbine recovery were assumed to be the main drivers behind operating costs. In terms of the level of future reduction in operating cost there is significant scope for a reduction of around 50%. For example, it is reported that a movement from large offshore wind based vessel solutions to smaller tidal specific solutions could reduce costs.

For the opex learning rate forecast Arup has developed its opex forecast based on information provided by stakeholders. Four categories of opex were considered which included fixed and variable O&M, insurance and grid costs. For both grid and insurance costs no data was available from either stakeholder, external or internal sources.

Appendix C, provides a summary of the cost index forecast applied to Tidal Stream. Based on an analysis of learning rates and deployment the reduction in opex cost is expected to be 16.7% by 2020, 33.3% by 2025 and 50.0% by 2030.

Table 199 Tidal Stream Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	160	144	127	110
Medium	235	211	186	161
High	301	270	238	206

15.4 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these to existing DECC assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Table 200 below provide current cost estimates for 2015, the DECC assumptions comparator and percentage change.

Arup has prepared an LCOE estimate which can be compared to DECC's current value. New and old cost estimates for pre-development, construction, and operating cost are presented below. The following provides Arup's view on what has caused the change in cost:

- **Pre-development cost:** stakeholders indicated that grid development, securities, EIA planning requirement and geotechnical surveys are the main drivers behind pre-development cost.
- Average timescales required to carry out technical development are estimated for the first time and are assumed to be around four years. It should be noted that a direct comparison between pre-development costs is not possible since the 2011 Study did not generate any estimates. The overall pre-development cost value has been assessed to be of the correct order.
- **Construction cost:** following a review of the stakeholder data Arup understand that the key drivers of cost include offshore installation, vessel and turbine recovery costs. Overall, excluding DECC's current cost reduction assumption (i.e. what cost was expected to be by 2015) the overall change is an increase in construction cost of around **30%**. The change matches current expectations that cost over the last five years has increased marginally as certainty around the cost of developing and delivering the technology has improved. It should be noted that the historic DECC costs used for LCOE modelling were inclusive of infrastructure cost. Arup's new cost estimates break this element out.
- **Operating cost:** following an internal and external review of the operating cost data it was concluded that the estimated change between DECC's current and the new cost estimates generated by Arup could be expected. Overall there has been a large increase in cost close to **40%** since the estimates were produced in 2011. The change has been driven largely by increases in fixed and variable costs and new cost items such as insurance and UoS.
- Reductions in operating cost are likely to be present when developers are able to spread their operational costs across a large number of sites and installed capacities. In addition, other important drivers include improvements in the supply chain and a better understanding of the project lifecycle.
- It should be noted that no insurance or grid UoS cost data was provided or available from external sources. Arup has therefore used an alternative benchmark cost from offshore wind.

Table 200 Tidal Stream Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices £'000/MW

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	128	128	128	128
	Construction	£/kW	5,205	4,698	3,910	3,059
	Infrastructure	£'000	7,375	7,375	7,375	7,375
	Total capex	**£/kW**	**5,750**	**5,243**	**4,455**	**3,605**
	Total opex	**£MW**	**235,382**	**210,726**	**186,071**	**161,415**
	Fixed O&M	£/MW	124,616	103,847	83,078	62,308
	Variable O&M	£/MWh	7.4	6.2	4.9	3.7
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	3,349	2,791	2,232	1,674
	UoS	£/MW	82,322	82,322	82,322	82,322
DECC Current	Pre-development	£/kW	0	0	0	0
	Construction	£/kW	4,007	3,025	2,617	2,368
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**4,007**	**3,025**	**2,617**	**2,368**
	Total opex	**£/MW**	**163,123**	**153,719**	**145,180**	**139,651**
	Fixed O&M	£/MW	161,746	152,422	143,955	138,472
	Variable O&M	£/MWh	0.5	0.5	0.5	0.4
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
	Pre-development	%	-	-	-	-

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	30%	55%	49%	29%
	Infrastructure	%	-	-	-	-
	Total capex	%	**43%**	**73%**	**70%**	**52%**
	Total opex	%	**44%**	**37%**	**28%**	**16%**

Arup reviewed the estimates it produced against benchmark costs from other renewable market reports. The objective here was to provide validation of the findings and provide comfort around the observations made. To understand the change in cost Arup analysed different development, construction and opex benchmark data. Overall, the following was observed when compared to the Arup 2015 figures:

- **Construction costs:** comparator data was available from WEC which estimated the range of cost to be £6,113/kW, to £5,884/kW respectively. The 2015 estimate of £5,205/kW sits below the current external cost estimate. Based on the collected data, internal and external review Arup is confident in costs used for the LCOE analysis
- **Operating cost**: data was available from WEC which indicated cost to be £86k/MW and £82k/MW. Arup's 2015 update is less than DECC's current estimate but above the values provided via external reports. It was concluded following an internal and external review that the operating cost value produced by the dataset was potentially high but followed the trend Arup expected i.e. increased cost certainty as projects have been rolled-out.

15.5 Technical Assumptions

Based on the data received from stakeholders and the benchmarks collected internally Arup was able to carry out a comparison between DECC's current LCOE technical assumptions and the new value generated by the 2015 Study. The following observations were made:

- **Net power:** the average scale of plant has reduced significantly from 100MW to 17.7MW. The reduction is understood to reflect current market conditions and the scale of project which developers expect to deliver at this point in time.
- **Availability:** it is understood that the typical availability for a tidal stream plant is expected to be 94%, allowing for downtime, parts replacement and maintenance inspection. The new assumption has replaced DECC's current high availability assumption of 100%.

- **Load factors:** following the stakeholder engagement and data collection process a review of the data was carried out. Arup understand that gross load factors at tidal stream sites are understood to have marginally improved from 31% to 33%. On a net basis the two load factors are very close: 31% and 30.8% respectively. Over the last five years it is understood that stakeholders have conducted additional research to establish more accurately load factors. The new estimates produced by Arup take into account expected plant scale for current and planned sites going forward. A summary of the load factors used for the analysis is provided in **Appendix B.**

Table 201 Tidal Stream Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	100.00	17.67	-82.33
Availability	%	100%	94%	-6.5%
Load factor (gross)	%	31%	33%	6.3%
Load factor (net)	%	31%	31%	-0.6%

The assumed load factor is presented below on Table 202; and the assumed installation lifetime is 22 years.

Table 202 Assumed Load Factor %

%	Tidal Stream
Medium, gross	32.9%
Medium, net	30.8%

15.6 Levelised Cost

Based on the learning rate forecast, capital and operating cost profiles Arup calculated LCOE for a tidal stream reference plant for a project commissioning (i.e. becoming operational in a specific year) in, 2025 and 2030 given the FOAK characteristics of the technology the results of the LCOE analysis should be interpreted with a degree of caution. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Table 204 provides the LCOE results based on DECC's updated hurdle rate for the technology.

Table 203 Tidal Stream LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low			221	178
Medium			343	279
High			468	383

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 204 LCOE 2016 – 2030 (Tidal Stream), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low			213	171
Medium			328	267
High			446	365

15.7 Comparison of DECC and Arup LCOE Values

Analysis of the underlying cost data indicates that for Tidal Stream there is an overall increase in LCOE when compared to the DECC's current values. The main drivers behind the increase are a large increase in both construction (£5,205/kW) and operating (£235k/MW) costs. Benchmark construction cost data ranges from £5,884/kW to £6,113/kW (WEC 2013). The Arup figure of £5,205/kW is close to low end of the range but above DECC's current cost assumption. This check against the benchmark provides a degree of comfort around the value which is being used for LCOE modelling purposes.

It should be noted that during the 2011 Study, it was assumed that project roll-out would have been greater, triggering learning effects and a reductions in LCOE over time. The level of project development and roll-out has not taken place at the expected levels. If roll-out of tidal stream projects continues it is reasonable to expect further reductions in cost over time as learning effects begin to take effect. However due to the FOAK nature of the technology the LCOE results are subject to a degree of uncertainty.

The following table compares new levelised cost estimate to previous DECC results. It should be noted that DECC previously published estimates for both tidal stream shallow and tidal stream deep. The previous estimates shown below are for tidal stream deep.

Table 205 Tidal Stream Comparison Arup vs. DECC, 2014 Real Prices £/MWh

%	Arup 2025	Arup 2030	DECC 2025	DECC 2030	% Change (2025)	% Change (2030)
Low	221	178	196	176	12.8%	1.3%
Medium	343	279	245	219	40.3%	27.7%
High	468	383	268	239	74.9%	60.5%

16 Wave

16.1 Introduction

Waves are formed by winds blowing over the surface of the sea. The size of the waves generated will depend upon the wind speed, its duration and the distance of water over which it blows (the fetch), bathymetry of the seafloor (which can focus or disperse the energy of the waves) and currents. The resulting movement of water carried (kinetic energy) can be harnessed by wave energy generators to produce electricity.

The best wave resources are located in regions where strong winds have travelled over long distances. In Europe this occurs along western coasts which lie along the Atlantic. In the UK the best wave resources are located in the North West of Scotland[48].

The UK continues to be a leader in the development of tidal stream technology. According to the OES' Annual Report in 2014 the UK had installed capacity of 3.7MW and approximately 40MW of projects consented. World leading test facilities and research centres carrying out analysis and research include the European Marine Energy Centre ('EMEC') in Orkney, Wavehub in Cornwall and Wave Energy Scotland. Commercial wave projects are being developed along with the infrastructure to facilitate deployment. Innovation is still required to develop commercial scale technologies and associated infrastructure to deploy new generation.

There are many types of wave design currently being delivered. There are eight main types of wave energy generator including: attenuator; point absorber; surge convertor; water column; overtopping; pressure differential; bulge wave; and rotating mass. For wave technology no disaggregation by technology was prepared for the Arup 2011 study. To maintain consistency with previous work Arup has not carried out any disaggregation by technology design for the 2015 Study.

16.2 Data Collection

Data was collected from public, internal and stakeholder sources. For the data collection process Arup primarily focussed on contacting projects developers, utility companies and trade associations. Overall Arup received very little data from industry with only two stakeholder data sets collected. Internally Arup was able to collect benchmark cost and operational data for five data points. In total the data collection resulted in nine data points.

Based on the data collection criteria outlined in Chapter Three, nine data points were assessed to be robust, representative and useful to the analysis. For the projects where data was received the installed capacity was small 8MW, reflecting the current early development stage of the technology.

[48] Please see: https://www.carbontrust.com/media/202649/ctc816-uk-wave-energy-resource.pdf

Although the overall data set was quite small it was assessed to be representative for current wave development projects in the UK. All results produced by the analysis were compared against collected benchmarks.

The nine data points represented projects at various stages of development (operational, under construction and planned). The average scale of plant calculated from was estimated to be 9MW.

16.2.1 Capital Expenditure

The following cost and technical information for wave is based primarily on data from stakeholders and external benchmarks. Capital expenditure for wave projects was based on the nine validated data points collected from various sources. The main cost items are reported to be focussed on cost of materials and labour.

Arup only received one data point related to pre-development cost which was very high when compared to the other technologies under review. The total pre-development cost reported was equal to 2.4m/MW. Pre-licencing and planning make up the majority of this significant cost. The stakeholder which provided this information did not provide any detail around what was driving the cost, however it is expected to be driven primarily by the complexity of design and permitting of sites.

The capital costs of wave varies between £4.2m/MW and £10.2m/MW, with a mean cost of £7.3m/MW. Table 206 below presents the range which includes pre-development, construction and infrastructure cost. An internal review of wave costs indicated that the majority related to construction and generation equipment. Infrastructure costs were assumed to include connection, transformer, sub-station and associated electrical infrastructure.

Table 206 Wave Capital Costs (2015 Financial Close), 2014 Real Prices £’000/MW

£’000/MW	Wave
Low	4,203
Medium	7,326
High	10,197

Table 207 below provides an indication of how capital costs is broken down for an average plant.

Table 207 Wave Capital Cost Breakdown for a Medium Project %

Capital cost item	Wave
Pre-development	1.7%
Construction	90.6%
Infrastructure	7.6%

16.2.2 Capital Cost Learning Rate Assumption and Forecast

In the UK there is now a significant body of research focussed on how the cost of wave technology could be reduced and commercialised. Recent publications from Renewable UK and ORE Catapult were reviewed and assessed to be a good source of data for learning rates.

For Arup's learning rate forecast four capex components were identified as areas where cost reduction is likely to take place. These are the PTO systems, installations, foundations and grid connection. Following the literature review the learning rate forecast was applied to the capex components identified. For the PTO system the learning rate was linked to global deployment of the technology. Installation, foundation and grid connection were linked to UK deployment of the technology.

As a technology at an early stage of development it is Arup's view that there is significant potential for learning effects in wave power. The potential for future cost reduction is likely to occur through continued optimisation of equipment manufacture, project delivery and a movement toward 'mass' manufacture of the wave generator systems. Overall, the learning rate forecast has estimated that there is the potential to reduce cost by over 50%.

The learning rate forecast uses deployment data from RenewableUK and the IEA to generate the expected change in learning rates. Different construction components were linked to either global or UK deployment. For the UK deployment is estimated to increase from 25MW in 2020 to 205MW in 2030. At the global level deployment is estimated to be 1,000MW by 2020 and 6,000MW by 2030.

There is expected to be continued downward pressure on construction cost in the future. **Appendix C**, provides a summary of the cost index forecast for tidal stream development. Based on an analysis of learning rates and deployment the reduction in cost is expected to be 21% by 2020, 38% by 2025 and 53% by 2030, which is equal to an annual reduction of -4.9%. However, due to the FOAK nature of the technology there is a degree of uncertainty around potential future cost reductions. The LCOE estimates must therefore be viewed with a degree of caution.

The learning rates have been estimated based on data from RenewableUK reports, stakeholders, the IEA and a UK focussed literature review. To obtain our rate 200MW of wave is expected to be deployed by 2030.

Table 208 Wave Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	4,203	3,414	2,745	2,161
Medium	7,326	5,960	4,802	3,792
High	10,197	8,312	6,714	5,321

16.3 Operating Cost

Operating costs for wave plant are understood to mainly comprise of fixed and variable O&M contracts, UoS charges, insurance and labour. Data provided by stakeholders was at a greater level of detail when compared with the 2010 Study. For example, data on variable, insurance and UoS costs were now available. The stakeholder and literature indicated that the key drivers of cost are vessel hire for maintenance, equipment, spare parts and transportation.

Table 209 below provides an indication of the variation in operating cost. Overall operating cost illustrate a wide ranges from £76k/MW to £322k/MW, with a mean of £212k/MW. Compared to DECC's current operating cost assumption, the mean figure has increased by around 4% reflecting a greater degree of certainty around wave operating costs.

16.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs Arup split the cost into the four categories, fixed and variable O&M, insurance and UoS. The literature review did not yield a large amount data in terms of a reliable view on the likely direction of cost. Stakeholder responses provided a more detailed view on the future direction. The key future driver is expected to include improvements in maintenance procedures and optimisation of lifecycle cost management, this is expected to result in an improvement in the reliability of wave generators and a reduction in operating costs over the long-run.

Appendix C provides a summary of the cost index forecast applied to wave. Based on an analysis of learning rates and deployment the reduction in opex cost is expected to be 19.3% by 2020, 38.6% by 2025 and 57.9% by 2030.

Table 209 Wave Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	Wave
Low	76
Medium	212
High	322

Table 210 Wave Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	76	65	54	44
Medium	212	181	150	119
High	322	274	227	180

16.4 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these to DECC's current assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Table 211 below provide current cost estimates for 2015, the DECC assumptions comparator and percentage change.

It should be noted that the cost data collected is for wave projects that are still at the planning and development stage. DECC's existing assumptions provide only one estimate of the scale of plant. To generate a comparison Arup has used DECC's current cost estimates and compared these with those generated by the updated analysis. New and old cost estimates for: pre-development, construction; and operating cost are presented below. The following provides Arup's view on what has caused the change in cost:

- **Pre-development cost:** two stakeholders provided data on pre-development cost which was very high relative to other renewable technologies at the FOAK stage of development. The total cost was reported to be around £2.4m/MW. Although not explicitly stated by the stakeholders a significant proportion of the cost related to planning and technical design. The significant pre-development costs had a major impact on LCOE. Therefore as a result of a lack of data Arup utilised pre-development costs from tidal stream as an approximation for future development costs.

- **Construction cost:** construction costs for wave indicate a decrease in cost of **22%** when compared to the current DECC assumptions. It is reported that key drivers for construction cost are improvements in design, investment and an improving supply chain[49].

- **Operating cost:** for wave there is a reported increase in total opex. It should be noted that a direct comparison between DECC's current assumptions and the 2015 Update is difficult since Arup's latest figures breakdown cost into a greater level of detail. Overall the increase in cost in the medium case is marginal at around **4%**, reflecting improvements in cost certainty around the lifecycle costs of wave generation. It is reported that the main cost drivers include vessel hire for maintenance, logistics and transportation equipment on land.

Table 211 Wave Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	128	128	128	128
	Construction	£/kW	6,641	5,275	4,117	3,107
	Infrastructure	£'000	5,075	5,075	5,075	5,075
	Total capex	**£/kW**	**7,326**	**5,960**	**4,802**	**3,792**
	Total opex	**£MW**	**212,478**	**181,427**	**150,375**	**119,324**
	Fixed O&M	£/MW	58,767	47,416	36,065	24,714
	Variable O&M	£/MWh	32.3	26.0	19.8	13.6

[49] Other sources of data include: ETI & UKERC marine energy roadmap; 2014 JRC Ocean Energy Status Report; OECD Projected Costs of Generating Electricity 2015; SIOcean - Ocean Energy: Cost of Energy and Cost Reduction Opportunities; Low Carbon Innovation – Marine Report

	Assumption	Unit	2015	2020	2025	2030
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	17,187	13,867	10,547	7,228
	UoS	£/MW	46,724	46,724	46,724	46,724
DECC Current	Pre-development	£/kW	115	115	115	115
	Construction	£/kW	8,493	5,816	4,082	3,161
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**8,608**	**5,932**	**4,197**	**3,277**
	Total opex	**£/MW**	**204,555**	**114,877**	**94,696**	**82,905**
	Fixed O&M	£/MW	204,555	114,877	94,696	82,905
	Variable O&M	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0
% Change	Pre-development	%	11%	11%	11%	11%
	Construction	%	-22%	-9%	1%	-2%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-15%**	**0%**	**14%**	**16%**
	Total opex	%	**4%**	**58%**	**59%**	**44%**

Arup reviewed the estimates it produced against benchmark costs from external reports. The objective here was to provide validation of the findings and provide comfort around the observations made. To understand the change in cost Arup analysed different development, construction and opex benchmark data for wave. Overall, the following was observed when compared to the Arup 2015 figures:

- **Construction costs:** comparator data was available from BNEF and IRENA which estimated the range of cost to be £5,567/kW and £5,463/kW respectively. The 2015 estimate of £6,641/kW is higher than the external cost estimate range. However, it was concluded that there is a large degree of uncertainty around wave cost, therefore a comparison with external data is difficult. Arup's dataset is based on stakeholder data and was subject to an internal and external review process with DECC. The review process has provided confidence around the final values used for LCOE modelling purposes.
- **Operating cost**: data was available from BNEF which indicated fixed operating cost to be £95k/MW. Arup's 2015 Update fixed cost is less than DECC's current value and the benchmark. It was concluded that the operating cost value produced by the dataset was potentially low but followed the trend Arup expected. After an internal and external review it was concluded that the value generated by the dataset should be used.

16.5 Technical Assumptions

Based on the data collected via internal and external source Arup was able to carry out a comparison between DECC's current LCOE technical assumptions and the new values generated by the Study. The following observations were made:

- **Net power:** the average scale of plant has reduced significantly from 15MW to 9.1MW. The reduction is understood to reflect current market conditions and the overall scale of projects that developers are expecting to deliver going forward.
- **Availability:** it is understood that the typical availability for a wave generation plant is now 81%, allowing for downtime, parts replacement and maintenance inspections. The new assumption has replaced DECC's current high availability assumption of 100%.
- **Load factors:** following the stakeholder engagement and data collection process a review of the data was carried out. Arup understand that gross load factors at wave generation plants are understood to have improved from 31% to 37%. However, on a net basis the two load factors are very close: at 31% to 30% respectively.

Table 212 Wave Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	15.00	9.11	-5.89
Availability	%	100%	81%	-18.6%
Load factor (gross)	%	31%	37%	18.8%
Load factor (net)	%	31%	30%	-3.2%

The assumed load factor is provided below. The assumed installation lifetime is 20 years which matches DECC's current cost assumptions.

Table 213 Assumed Load Factor %

%	Wave
Medium, gross	36.8%
Medium, net	30.0%

The minimum, average and maximum load factor was calculated based on data from internal benchmarks and stakeholders. For each year in the LCOE forecast Arup has assumed the average, minimum and maximum of load factors from the data collet. And help and held these constant for the entire appraisal period

16.6 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for a wave reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The f following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates.

Table 215 provides the LCOE results based on DECC's updated hurdle rate for the technology.

Table 214 Wave LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low			214	166
Medium			333	262
High			444	352

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 215 LCOE 2016 – 2030 (Wave Energy), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low			207	161
Medium			320	252
High			427	338

16.7 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup's new cost data, DECC's current assumptions and discount rates. Overall the current data indicates that a project commissioning by 2025 and 2030 will have an LCOE which is approximately 18% and 19% higher when the two figures are compared.

Table 216 Wave Comparison Arup vs. DECC, 2014 Real Prices £/MWh

%	Arup 2025	Arup 2030	DECC 2025	DECC 2030	% Change (2025)	% Change (2030)
Low	214	166	247	192	-13.4%	-13.4%
Medium	333	262	283	219	17.6%	19.4%
High	444	352	299	231	48.8%	52.2%

17 Deep Geothermal (CHP)

17.1 Introduction

Geothermal CHP is the simultaneous generation of electricity and heat. CHP is designed to utilise heat produced as a by-product typically for space heating and hot water. In the UK Geothermal CHP is at an early stage of project development. Currently the geothermal projects under development in the UK are heat only projects where the heat would be supplied to district heating networks. Planned projects include those in Crewe, Manchester, North Tyneside and Stoke. There is only one existing deep geothermal scheme in UK, at Southampton, which forms part of the city centre district heating scheme and has been operating since the 1980s. The Government is supporting innovative ways to make use of geothermal energy for small scale heat networks.

The UK has a number of areas identified which contain low and medium grade heat resource, but the UK does not have the resource potential of volcanic regions, for example such as that in Iceland or New Zealand, for geothermal CHP plants.

Compared to other renewable technologies geothermal CHP in non-volcanic regions is one of the least commercially ‘proven’. In the UK geothermal CHP is a high upfront cost technology. It should be noted that data for the analysis was limited. Arup used where possible information from stakeholders, benchmarks and reputable published sources of information. This included benchmark from IRENA, WEC, BNEF and IEA. In addition, reports produced by SKM, Ricardo-AEA, Atkins and the European Geothermal Council have also proved to be important sources of information. Where gaps in the data were identified (e.g. insurance), an alternative benchmark was used.

Future innovation and cost reduction within the technology is expected if the rate of project development can be increased. Currently geothermal CHP is a high-cost technology with considerable work required to locate sites with suitable geothermal resource. To manage project risk schemes are developed using a phased approach to estimate capital costs, locate sites and customers.

Key challenges for the technology include better use of the heat generated, improvements in efficiency and finding sites close to heat customers.

For the analysis the generation cost information was supplied mainly by published reports[50] and internal sources. For the Arup 2011 study DECC had previously requested that the data was collated for geothermal with and without CHP i.e. power only and heat and power. For the 2015 Update Arup again attempted to collect data for both. There were however few responses for this technology, therefore due to a lack of robust data Arup has prepared cost estimates for geothermal CHP only.

[50] Cost and technical performance data for UK projects was also collected from Atkins, Deep Geothermal Review Study for Department of Energy and Climate Change, October 2013. In addition cost data was also collected from internal sources.

It should be noted that there was very limited responses from stakeholders. Where there was a shortage of data, Arup has used alternative published sources. It was assumed that the typical operational life ranged from 20 to 30 years with a medium life of 25 years.

The data collected by Arup was assessed to representative and useful for the analysis. Based on an understanding the early development stage of UK geothermal, it is Arup's view that geothermal CHP plants going forward will operate in CHP-mode, selling both heat and electricity.

17.2 Data Collection

To generate data points for the analysis Arup collected data from internal and published sources with a focus on the UK. At the start of the data collection process Arup contacted manufacturers, developers, trade associations and utility companies. Overall data was collected from internal benchmarks and reports, yielding initially 16 projects data points.

Based on the data collection criteria outlined in Chapter Three, 11 data points were assessed to be robust, representative and useful for the analysis. All results produced during the analysis were compared with available benchmarks. Post evaluation the 11 data points were used for the analysis with an average installed capacity of 3.0MW.

17.2.1 Capital Expenditure

Pre-development costs have been reported to vary significantly between £0.080m/MW to £0.13m/MW shared equally between pre-licensing, planning and technical development. The medium cost was calculated to be £0.11m/MW. The collated data indicated pre-development costs varied widely and are quite site specific and not necessarily related to the overall scale of the project.

For all forms of geothermal CHP the most significant cost relates to the generation equipment and borehole drilling. For the average ('medium') project construction cost is equal to around £6.9m/MW[51]. Other costs such as grid connection and civil infrastructure represent around additional £0.12m/MW. Pre-development cost which include achieving planning permission, regulatory compliance and design average around £0.11m/MW. Combining the pre-development, construction and infrastructure costs together total £7.13m/MW.

[51] Cost estimate includes data from section eight of Atkins Deep Geothermal Review Study in addition to stakeholder, internal and external benchmark information. Please note that the construction cost figure of £6.9m/MW is assumed to comprise of: infrastructure for drilling; equipment; mobilisation; well testing; reservoir engineering; network monitoring; and CHP power plant equipment. The external review provided a benchmark figure of £1.5m/MW for borehole drilling, comparing well with the internal per well figure of £1.2/MW.

Table 217 Geothermal CHP Capital Costs (2015 Financial Close), 2014 Real Prices CHP-mode £'000/MW

£'000/MW	Geothermal CHP
Low	3,149
Medium	7,131
High	9,656

Table 218 Geothermal CHP Capital Cost Breakdown for a Medium Project %

Capital cost item	Geothermal CHP
Pre-development	1.5%
Construction	96.9%
Infrastructure	1.6%

17.2.2 Capital Cost Learning Rate Assumption and Forecast

Based on publically available reports and internal knowledge an Arup view on the future direction of cost was prepared and developed into a learning rate forecast. All the reports reviewed indicated an expectation for significant future reductions in capital cost. For the forecast Arup has used data mainly from the IEA's World Energy Outlook 2014 to generate its capex costs forecast.

From a construction cost perspective the main cost drivers are reported to be exchange rates, availability of finance, labour and commodity prices (steel and copper). In addition, it is also reported that the cost and availability of onshore drilling rigs also potentially a big issue. For example, when oil is cheap so is drilling rig and equipment costs; when oil is expensive geothermal is disadvantaged and struggles to pay high rig rates. Over the long-run the consensus within the literature review appears to indicate a fall, resulting from improved efficiency in project delivery, learning effects and technical advances with deployment of the technology. Reductions in capital costs would be expected following deployment at scale in the same geological setting. This is due to increased knowledge and characteristics of the sub-surface and therefore a reduction in the risk from unproductive boreholes[52].

Appendix C, provides a summary of the cost index forecast which has been applied to geothermal CHP. Based on an analysis of learning rates and deployment the decrease in cost is expected to be 2% by 2020, 4.6% by 2025 and 6.7% by 2030, which is equal to an annual reduction of -0.5%. The learning rates have been estimated based on data from the IEA.

Table 219 Geothermal CHP Capital Cost Forecast 2015 – 2030, 2014 Real Prices CHP-mode £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	3,149	3,088	3,009	2,947
Medium	7,131	6,991	6,811	6,670
High	9,656	9,467	9,223	9,031

17.3 Operating Cost

Operating costs for geothermal CHP plants are primarily driven by the labour required to operate and maintain production and generation equipment. Operational costs shows a wide range reflecting uncertainty around project cost within the dataset. The wide variance in cost implies that the cost of operating geothermal CHP plant is still relatively uncertain and will require further deployment before operating costs become more certain. Arup would therefore view the current estimates presented in this report with a degree of caution.

Table 220 below provides an indication of the variation in operating cost between the categories. Overall for Geothermal CHP the cost ranges from £114k/MW to £238k/MW, average operating cost is around, £187k/MW and is expected to be mainly driven by project specific project conditions, availability of equipment, skilled labour.

17.3.1 Operating Cost Learning Rate Assumption and Forecast

For geothermal CHP operating cost the analysis identified labour and the availability of components as an important cost driver. For the opex learning rate forecast Arup reviewed information provided via internal sources and external reports. Overall, Arup concluded that no reliable view on the future direction of

[52] The International Finance Corporation (Success of Geothermal Wells: A Global Study, June 2013) has published an important geothermal study analysing the risks around project success. Based on global project an important finding is there is strong learning-curve effect associated with geothermal drilling, with the success rate improving as more wells are drilled.

operating cost was available. Therefore, for the LCOE modelling Arup has assumed constant operating costs.

Appendix C, provides a summary of the cost index forecast applied to geothermal CHP. As a result of a lack of data and few projects being delivered to data, it is Arup's view that opex costs should remain at the current level.

Table 220 Geothermal CHP Operating Costs (Financial Close 2015), 2014 Real Prices CHP-mode £'000/MW

£'000s/MW	Geothermal CHP
Low	114
Medium	187
High	238

Table 221 Geothermal CHP Operating Cost Forecast 2016 – 2030, 2014 Real Prices CHP-mode £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	114	114	114	114
Medium	187	187	187	187
High	238	238	238	238

17.4 Cost Breakdown

Based on the collected data Arup was able to generate new cost figures and compare these to existing DECC assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving the change. Table 222 provides current cost estimates for 2015, the DECC assumptions comparator and percentage change.

It should be noted that the number of data points captured for the analysis is relatively small. Therefore, a comparison between DECC's figures and the 2015 Update is difficult.

It should be noted that the cost data collected was for projects at either the feasibility or early stages of planning. Arup has used DECC's exiting cost estimates and compared these to those generated by the updated analysis. New and old cost estimates for: pre-development, construction; and operating cost are presented below along with a view on what has caused the change in cost:

- **Pre-development cost:** the cost comparison indicates a fall in cost of around **30%**. The reason for the fall is expected to be a result of improvements in certainty around development costs, regulatory compliance and technical design. Developers are understood to have a better understanding of the cost of selecting sites.
- **Construction cost:** a comparison of the current DECC assumptions and the Arup 2015 update indicates a large overall increase in construction cost of around **50%**. It should be noted that the current DECC assumption expected construction cost to reach £4.7m/MW by 2015; learning and cost reduction has not taken place at the expected rate. In the UK Geothermal CHP is a relatively new technology to be deployed with a large variance expected between projects until learning effects have taken place. Based on the available data and our knowledge that geothermal CHP costs is uncertain relative to other technologies, there is some scope for additional large cost reductions.
- **Operating cost:** key costs are understood to include labour costs (which has remained relatively flat) and availability of equipment and parts. Overall operating cost is reported to have fallen by around **8%**.
- Variable costs is noted as being marginally higher relative to the current DECC assumptions. The current variable cost estimates is based on recent estimates, therefore we are confident in the figure.

Table 222 Geothermal CHP Cost Comparison between Arup 2015 and DECC Current, 2014 Prices CHP-mode

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	106	106	106	106
	Construction	£/kW	6,907	6,768	6,588	6,447
	Infrastructure	£'000	349	349	349	349
	Total capex	**£/kW**	**7,131**	**6,991**	**6,811**	**6,670**
	Total opex	**£MW**	**187,074**	**187,074**	**187,074**	**187,074**
	Fixed O&M	£/MW	81,016	81,016	81,016	81,016
	Variable O&M	£/MWh	9.7	9.7	9.7	9.7

	Assumption	Unit	2015	2020	2025	2030
	BSUoS	£/MWh	1.9	1.9	1.9	1.9
	Insurance	£MW	1,620	1,620	1,620	1,620
	UoS	£/MW	12,921	12,921	12,921	12,921
DECC Current	Pre-development	£/kW	149	149	149	149
	Construction	£/kW	4,661	4,565	4,438	4,339
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**4,809**	**4,714**	**4,587**	**4,488**
	Total opex	**£/MW**	**204,221**	**204,828**	**205,438**	**206,049**
	Fixed O&M	£/MW	35,524	35,631	35,738	35,845
	Variable O&M	£/MWh	10.8	10.9	10.9	10.9
	Insurance	£/MW	80,116	80,357	80,598	80,840
	UoS	£/MW	2,005	2,005	2,005	2,005
% Change	Pre-development	%	-28%	-28%	-28%	-28%
	Construction	%	48%	48%	48%	49%
	Infrastructure	%	-	-	-	-
	Total capex	%	**48%**	**48%**	**48%**	**49%**
	Total opex	%	**-8%**	**-9%**	**-9%**	**-9%**

Arup reviewed the estimates it produced against benchmark costs from external reports. The objective here was to provide validation of the findings and provide comfort around the observations made. To understand the change in cost Arup analysed different development, construction and opex benchmark data for Geothermal CHP. Overall, the following was observed when compared to the Arup 2015 figures:

- **Construction costs:** comparator data was available from a wide range of international sources including IRENA, WEC, BNEF, IEA and Lazard. The estimated range of cost from these is between £3,798/kW and £1,680/kW. The 2015 estimate of £6,907/kW is significantly higher than the external cost estimate range. It is a UK focussed number where geothermal is still to become an established technology. It should be noted that the external benchmarks are more likely to reflect international construction costs where geothermal CHP is an established technology. Therefore, Arup reflected on the available benchmarks but following a review decided to rely upon its internal benchmark data and discussions with DECC.

17.5 Technical Assumptions

Based on the data received from developers Arup was able to carry out a comparison with DECC’s current LCOE technical assumptions. The following provides a summary of the observations made:

- **Net Power:** based on the data provided by stakeholders the average installed capacity was estimated to be 3.0MW. When compared to DECC’s current assumption there has been an observed reduction from 6.8MW. It is understood that stakeholders are primarily focussed on developing smaller scale sites located close to sources of heat demand.
- Steam output was also noted as decreasing significantly between DECC’s current and Arup’s 2015 updated figure 22.1MWth to 11.5MWth. The change has conformed to Arup’s expectation and correspond with the reduction in installed capacity.
- **Availability:** no data was available for the analysis. In the absence of data Arup collected load factor benchmark data which was reported to be net of availability. For the purposes of the LCOE calculation Arup has therefore assumed availability value of 100%.
- **Load factors:** for geothermal CHP the load factor is understood to have decreased marginally from 91% to 90% when compared on a net basis. Following and internal and external review the current medium figure appears to be within the expected range Arup would typically expect. A summary of the load factors used for the analysis are provided in **Appendix B.**

Table 223 Geothermal CHP Technical Assumptions CHP-mode

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	6.80	2.99	-3.81
Average steam output	MWth	22.14	11.50	-10.64
Net LHV efficiency	%	100%	100%	0.0%
Availability	%	94%	100%	7.0%
Load factor (gross)	%	98%	90%	-7.3%
Load factor (net)	%	91%	90%	-0.8%

The assumed load factor used is presented below on table 224 and the assumed installation lifetime is 25 years.

Table 224 Assumed Load Factor %

%	Geothermal CHP
Medium, gross	90.4%
Medium, net	90.4%

17.6 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup calculated LCOE for the geothermal CHP reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC’s hurdle rates. Table 226 provides the LCOE results based on DECC’s updated hurdle rate for the technology

The LCOE modelling load factor is based on internal and external data for the minimum, average and maximum. It is held constant with no change due to limited information surrounding the technology. The following provides the low, medium and high levelised cost for each technology under review.

It should be noted that the LCOE for geothermal is very wide and reflects the range of underlying capital cost and operating cost data. The cost data has been assessed to be representative for a new geothermal CHP project.

Table 225 Geothermal CHP LCOE 2016 – 2030, 2014 Real Prices CHP-mode* £/MWh

£/MWh	2016	2020	2025	2030
Low	32	32	7	-4
Medium	181	181	153	139
High	276	276	245	229

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 226 LCOE 2016 – 2030 (Geothermal CHP), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	34	34	9	-2
Medium	184	184	156	141
High	280	280	249	232

17.7 Comparison of DECC and Arup LCOE Values

The following summary tables provide a comparison between LCOE based on Arup's new cost data, DECC's current assumptions and discount rates. A summary of all the LCOEs generated using DECC's current and new hurdle rates are presented in **Appendix I.**

For Geothermal CHP the data indicate that a project starting in 2016 or commissioning by 2020 will have an LCOE which has increased by 16% and 15% respectively. The main driver behind the observed change is a large increase in the expected capital cost, which is partly offset by an expected improvement in heat revenues. For comparison purposes the current DECC figures have been inflated from 2012 to 2014 prices.

Table 227 Geothermal CHP Comparison Arup vs. DECC, 2014 Prices CHP-mode £/MWh

£/MWh	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	32	32	54	55	-40.0%	-41.1%
Medium	181	181	156	158	16.4%	15.0%
High	276	276	243	246	13.4%	12.3%

18 Biomass Co-firing

18.1 Introduction

Biomass co-firing has essentially been provided by existing coal fired capacity and is expected to be linked to the future of coal fired generation in the UK. Environmental requirements such as LCPD and IED, combined with increasing carbon prices have led to the closure and reduction of electricity generation from existing coal fired power stations. Whilst co-firing has become a significant contributor to renewable generation may reduce to zero in the short-term. Plants that have opted out of the LCPD must cease operation by 31 December 2015.

Over the last five years solid biomass co-firing has made a significant contribution toward renewable energy generation in the UK. Co-firing will generally use high-quality biomass, delivered in pellet form which is also the preferred feedstock for biomass conversion plant

The key factors influencing the deployment and co-firing of plant are environmental emission requirements, performance standards and the role of coal in the UK energy market. Plants which opted out of the LCPD that have closed or are scheduled to include: Cockenzie; Didcot; Eggborough; Ferrybridge; Kingsnorth; and Tilbury.

Coal generation plant which is fitted with flue-gas desulfurization (‘FGD’) will be subject to the Industrial Emissions Directive (IED) from 2016. Whilst some of these will invest in further environmental controls (principally Selective Catalytic Reduction (‘SCR’) to reduce NOx, most will probably make use of either the delayed compliance options (nominally compliance by 2020) or the IED opt out provisions which allow continued, but limited, operation until 2023, then closure.

Therefore post-2015 it is Arup’s view that the likelihood of new plants and mothballed plants co-firing in the future is small. In addition, the load factor on remaining plant will is expected to fall further, further limiting energy produced from biomass co-firing. It is therefore Arup’s view that if a plant is likely to come forward it is more likely to go for full conversion.

For the purposes of LCOE modelling it is therefore assumed that the most likely type of co-firing plant to be deployed would be of the ‘Advanced’ co-firing type. In terms of equipment, infrastructure and cost advanced co-firing sites are understood to be very close to biomass conversion plant.

18.2 Data Collection

For cofiring there is a severe lack of data for the analysis. To generate data points for the analysis Arup contacted stakeholders, reviewed internal and external reports. Overall none of the primary and secondary sources of data yielded any new data. Therefore, based on the data collection criteria outlined in Chapter Three no data review took place. In the absence of data Arup has used its dataset from the 2011 study for Advanced Co-firing and applied an adjustment factor to the construction cost. This dataset has previously not been published by DECC given concerns over data robustness.

In terms of installed capacity the Arup's current data represents an average project size of 538MW. As a result of no data being available Arup was unable to assess whether the average scale of plant had either increased or decreased between the two reviews. For the LCOE analysis Arup assumed DECC's current scale of plant.

18.2.1 Capital Expenditure

For advanced co-firing plant the vast majority of capital expenditure is understood to be related to construction costs which include boiler replacement, construction of biomass storage facilities and modifications to material handling systems. In some cases modifications to local infrastructure such as rail network upgrades and port infrastructure may also be required. It is assumed that the co-firing plants will already have an electrical connection in place.

Capital expenditure for advanced co-firing plant is based on Arup's current assumptions. Pre-development costs is assumed to be fixed at £60k/MW in the low, medium and high. It includes pre-licensing, technical design which like conversion is bespoke to the specific plant, development costs, regulatory and environmental compliance reporting.

In terms of cost and the technical requirements to deliver an advanced co-firing project Arup has assessed the requirements to be broadly similar to biomass conversion. Therefore, in the absence of data Arup would has applied the change in conversion cost (2010 to 2015) to Arup's advanced co-firing dataset to generate new construction costs.

It is important to note that cost will be bespoke to the actual plant. The new estimates range between £209k/MW to £480k/MW with a mean cost of £306k/MW.

Table 228 Co-firing Capital Costs (2015 Financial Close), 2014 Real Prices £'000/MW

£'000/MW	Co-firing
Low	209
Medium	306
High	480

Table 229 Co-firing Capital Cost Breakdown for a Medium Project %

Capital cost item	Co-firing
Pre-development	19.6%
Construction	80.4%
Infrastructure	n/a

18.2.2 Capital Cost Learning Rate Assumption and Forecast

Based on an assumption that advanced co-firing is similar in its design to conversion. Arup was able to form its view on the future direction of construction cost. It was concluded that capital costs are unlikely to change, with no additional downward pressure and the majority of industry learning already taken place Overall, construction cost is expected to be remain flat. **Appendix C**, provides a summary of the cost index forecast which has been applied.

Table 230 Co-firing Capital Cost Forecast 2015 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	209	209	209	209
Medium	306	306	306	306
High	480	480	480	480

18.3 Operating Costs

Operating costs for advanced co-firing plant comprise mainly of fixed and variable O&M contracts, UoS charges, insurance and labour. The following table illustrates the contribution of each elements of cost. Labour cost as part of O&M contracts is understood to be the main driver of plant operating cost. If advanced co-firing plant is to be developed in the future, the typical UK based stakeholder which owns these type of asset will already have significant experience in operating plant. Arup therefore does not anticipate any significant learning effects

The following provide the current range of operational costs and how these can be expected to change over time to 2020, 2025 and 2030. Table 231 below provides an indication of the variation in operating cost between categories. Overall for the UK the cost is expected to be for all ranges around £69k/MW.

18.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs stakeholders identified labour and availability of components as an important cost driver. Broadly stakeholders did indicate that cost is expected to remain broadly flat going forward.

Appendix C, provides a summary of the cost index forecast applied to co-firing. Based on an analysis of learning rates and deployment opex cost is expected to remain stable at its current level.

Table 231 Co-firing Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	Co-firing
Low	69
Medium	69
High	69

Table 232 Co-firing Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	69	69	69	69
Medium	69	69	69	69
High	69	69	69	69

18.4 Biomass Fuel Prices

Co-firing and converted plant will generally need high-quality biomass, delivered in in pellet form. Arup has collated and reviewed biomass fuel price data from stakeholder and benchmark sources and the European Commission[53]. The stakeholder data indicated that the typical fuel input used in biomass conversion is

[53] http://ec.europa.eu/competition/state_aid/cases/255986/255986_1634646_59_2.pdf

imported wood pellets and expected to be the same used in co-firing. The use of wood pellets conformed to Arup's expectation and work within the industry.

The following has been assumed to generate a £/MWh value for the LCOE model:

- A GCV of 17 GJ/tonne;
- To convert from GJ to MWh a conversion of 3.6 is applied..

Arup has been able to estimate a minimum, average and maximum biomass price presented on table 233 below. The medium value of 28.96/MWh can be compared to DECC's assumption of £29.18/MWh. The data indicated that there has been only a marginal fall in wood pellet prices. The change in price is attributed to improvements in the UK biomass supply chain, investment in wood pellet handling facilities (ports, rail) and an increase in availability of wood pellets. Table 233 provides a summary of the estimated biomass prices paid for by co-firing plant operators. It should be noted that co-firing plant will typically use a fuel that has a high energy content relative to other forms of biomass generation. For example, dedicated biomass and biomass CHP were assessed to typically use waste wood as the main source of fuel, as opposed to more expensive forms of wood pellets[54].

It should be noted that biomass fuel prices are assumed to remain constant over the appraisal period. Stakeholders did not provide a view on the expected future direction of price and secondly, it is Arup's expectation that co-firing developers will enter into a long-term fuel supply contract typically 5 to 10 years in duration.

Table 233 Biomass Fuel Price Assumptions Forecast 2015 – 2030, 2014 Real Prices £/MWh

£/MWh	2015	2020	2025	2030
Low	26.24	26.24	26.24	26.24
Medium	28.96	28.96	28.96	28.96
High	36.76	36.76	36.76	36.76

Based on Arup's advanced co-firing dataset Arup has been able to generate new cost figures for comparison with Arup's current assumptions. The objectives of the analysis was to identify where costs had changed and understand what is driving change. Table 234 provides the current cost estimated for 2015, the DECC assumptions comparator and percentage change.

[54] Please note that Co-firing biomass fuel prices are based on the same data as conversion plant.

Arup has compared DECC's current cost estimates with those generated by the analysis. New and old cost estimates for: pre-development; construction and infrastructure have been produced along with Arup's view on what has caused the overall change in cost. The following provides Arup's view on what has caused the change in cost between DECC's current cost assumptions and Arup's 2015 work:

- **Pre-development cost:** Arup has applied a GDP deflator to uplift the DECC's current cost assumptions from 2012 to 2014 prices. Arup would expect the same drivers reported for co-firing to be relevant for advanced co-firing plant. Although no data was available stakeholders reported that the increase in cost was partially driven by increasing technical design and planning related costs. Again it should be noted that the costs associated with the technical and design elements is bespoke to the plant. In the absence of any reliable evidence Arup has only applied the GDP deflator index.

- **Construction cost:** a comparison of the Arup 2011 data to the Arup 2015 update indicates around a **40%** reduction in total capex cost. The change in conversion cost has therefore been applied to the advanced co-firing data set to generate new figures for LCOE modelling. Challenges around standardising delivery of the technology would have to be overcome. Overall, it no additional learning effects are expected to take place.

- **Operating cost:** Arup has applied the GDP deflator to uplift the Arup's current cost assumptions from 2012 to 2014 prices. Arup would expect the same drivers reported for co-firing to be relevant for advanced co-firing plant. Although Arup understand that the key cost driving operating costs include labour, the price of chemicals and disposal of hazardous waste. Again it should be noted that the costs associated with the technical and design elements is bespoke to the plant. In the absence of any reliable evidence Arup has only applied the GDP deflator index.

Table 234 Co-firing Cost Comparison between Arup 2015 and Arup 2011, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	60	60	60	60
	Construction	£/kW	246	246	246	246
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**306**	**306**	**306**	**306**
	Total opex	**£MW**	**68,747**	**68,747**	**68,747**	**68,747**
	Fixed O&M	£/MW	42,381	42,381	42,381	42,381
	Variable O&M	£/MWh	1.5	1.5	1.5	1.5
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	1,336	1,336	1,336	1,336
	UoS	£/MW	18,079	18,079	18,079	18,079
DECC Current	Pre-development	£/kW	60	60	60	60
	Construction	£/kW	453	441	436	431
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**513**	**501**	**495**	**491**
	Total opex	**£/MW**	**68,899**	**69,051**	**69,205**	**69,358**
	Fixed O&M	£/MW	42,509	42,636	42,764	42,893
	Variable O&M	£/MWh	1.5	1.5	1.5	1.5
	Insurance	£/MW	1,340	1,344	1,348	1,352
	UoS	£/MW	18,079	18,079	18,079	18,079
	Pre-development	%	0%	0%	0%	0%

	Assumption	Unit	2015	2020	2025	2030
% Change	Construction	%	-46%	-44%	-44%	-43%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-40%**	**-39%**	**-38%**	**-38%**
	Total opex	%	**0%**	**0%**	**-1%**	**-1%**

18.5 Technical Assumptions

The technical assumptions for were adapted from the Arup 2011 dataset.

Table 235 Co-firing Technical Assumptions

Assumption	Unit	Arup 2011	Arup	Change (%, net)
Net Power	MW	537.50	537.50	0.0%
Net LHV efficiency	%	36%	36%	0.0%
Availability	%	75%	75%	0.0%
Load factor (gross)	%	73%	73%	0.0%
Load factor (net)	%	54%	54%	0.0%

The assumed load factor is presented below on table 236 and the assumed installation lifetime of 15 years.

Table 236 Assumed Load Factor %

%	Advanced Co-firing
Medium, gross	72.5%
Medium, net	54.4%

Data from internal and external benchmark sources (Poyry, Platts) were available and compared with the load factors from DECC's published sources including DUKES. It is expected that biomass conversion plant will operate at a similar level to historic coal plant i.e. achieving a load factor of 75% or greater. It is therefore Arup's view that over the long-run the current load factor assumed here is representative.

18.6 Levelised Cost

Based on the learning rate forecast capital and operating cost profiles Arup has calculated LCOE for an advanced co-firing reference plant for a project starting in 2016 and commissioning (i.e. becoming operation in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's hurdle rates. Table 238 provides the LCOE results based on DECC's updated hurdle rate for the technology

Table 237 Co-firing LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	101	101	101	101
Medium	103	103	103	103
High	107	107	107	107

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 238 LCOE 2016 – 2030 (Co-firing Enhanced), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	101	101	101	101
Medium	103	103	103	103
High	107	107	107	107

18.7 Comparison with previous Arup LCOE Values

The following summary tables provides a comparison between LCOE based on Arup's new cost data, current assumptions and discount rates. A summary of all the LCOE generated using the current and new hurdle rates is presented in **Appendix I.**

For biomass co-firing projects the data indicates that a project starting in 2016 and becoming operational by 2020 (two years development and construction periods) has an estimated LCOE of -11% less than current estimates. As discussed above, the drivers of this reduction are falls in construction cost and an increase in load factor.

Table 239 Co-firing Comparison Arup vs. DECC, 2014 Real Prices £/MWh

£/MWh	Arup 2016	Arup 2020	Arup 2011, 2016	Arup 2011, 2020	% Change (2016)	% Change (2020)
Low	101	101	112	112	-10.0%	-10.0%
Medium	103	103	117	117	-11.4%	-11.4%
High	107	107	124	124	-13.7%	-13.7%

19 Hydro

19.1 Introduction

Hydropower generation converts the kinetic energy of water into electrical energy as water falls from a height to drive a turbine. The technology is highly developed, mature and reliable with a well understood lifecycle relative to other renewable technologies and with some plants been in operation for over 100 years.

Hydropower in the UK is a developed sector and based on a mature technology with the majority of hydro generators located in Scotland and Wales. In total it is estimated that the total installed capacity of all types of hydro available for generation is 5,280MW. In the UK there are now limited opportunities to deliver new large-scale hydro projects with developers currently focussed on delivering projects at smaller scales and at increasingly remote locations. The following provides an overview of the hydro technologies

Impoundment: is the most widespread technology in large hydro power sites, categorised by a large reservoir to store water (potential energy) held by a dam. In order to generate the electricity, water is released from the dam and flows through a turbine to generate power. This type of plant is typically used for base load electricity generation, but can also be used to provide flexible peaking power subject to the availability of water within the reservoir.

Impoundment schemes are associated with dams and reservoirs that store, release and control water flows through the generators and river system. These type of asset tend to be larger and can be operated and dispatched in a dispatchable and controlled way. In this sense it is easier to optimise performance and generate electricity when it is required when compared to run-of-river projects.

Diversion: also known as run-of-river this technology involves channelling a portion of river flow through a manmade canal or penstock (sluice gate), which is then used to spin a turbine. Generation profiles under this technology are subject to seasonal river flows. In the UK it is understood that run-of-river schemes are the most common type of hydro plant currently being planned and delivered. The minimal storage of this technology requires it to operate as base load generation taking the current available market price.

The Study aimed to collect data on two types of hydro scheme. The first was hydro plants with an installed capacity >5MW. It should be noted that the data Arup received from developers represented projects with an installed capacity of <5MW, reflecting current market conditions and developers moving toward small-scale hydro project when compared to historic plant delivery.

19.2 Data Collection

Arup attempted to collect data from public, internal and stakeholder sources. For the data collection process Arup primarily focussed on contacting projects developers, utility companies and trade associations. Arup received very little data for the installed scale and type of plant the Study was interested in. Benchmark data was available internally however it was for project at the small-scale and reflecting current market conditions. No data was available for a hydro project with an installed capacity >5MW in scale, therefore following internal and external discussions it was agreed that the Arup 2011 construction costs would be updated to 2015 values. All technical assumptions were assumed to remain the same as previous.

After an internal discussion it was concluded that the ‘best’ available index which should be applied to cost. The first step was to update the costs from 2012 to 2014 values, following the inflationary adjustment the change in the ‘European Power Capital Cost Index’ was applied to construction costs for the period 2010 to 2014 was. Based on the index it was assumed that there has been a small increase in cost of 0.3%. It should be noted that the index was only applied to construction costs only.

19.2.1 Capital Expenditure

For both hydro 5-16MW and hydro large store projects pre-development cost can vary significantly for £0.04m/MW to £0.30m/MW with a medium cost of £0.06m/MW. The driver behind the large variation in cost could be related to the complexity of identifying and permitting suitable sites. In addition, the type of hydro plant will be critical with the technical design costs in general greater for run-of-river projects relative to hydro projects with storage and dams.

The construction costs of hydro projects varies significantly between projects. For 5-16MW project costs vary between £1.6m/MW and £3.1m/MW with a medium cost of £3.0m/MW. For the low end of the range it is likely to represent ‘easier’ to access sites with build conditions that are more certain relative to the high end of the cost range. For large store projects one construction cost is assumed across the low, medium and high £3.2m/MW as not data on a capital costs range is available in the previous dataset. Please note that no infrastructure cost data was available for analysis and adjustment.

Table 240 below present capital cost. The following includes pre-development and construction (infrastructure cost are assumed to be captured within construction). It is expected that the majority of capital cost relate to construction and generation equipment installation. The cost of labour, steel, concrete were understood to be the principal drivers of cost, it should be noted that due to a lack of data from the stakeholder engagement no external views were taken into account on the future direction of cost. For LCOE modelling purposes cost is not assumed to change over time.

Table 240 Hydro 5-16MW Capital Costs (2015 Financial Close), 2014 Real Prices £’000/MW

£’000/MW	Hydro 5-16MW
Low	1,597
Medium	3,014
High	3,378

Table 241 Hydro Large Store Capital Costs (2015 Financial Close), 2014 Real Prices £’000/MW

£’000/MW	Hydro large store
Medium	3,283

Table 242 and 243 below provides an indication of how capital costs are broken down for an average plant.

Table 242 Hydro 5-16MW Capital Cost Breakdown for a Medium Project %

Capital cost item	Hydro 5-16MW
Pre-development	1.8%
Construction	98.2%
Infrastructure	0.0%

Table 243 Hydro Large Store Capital Cost Breakdown for a Medium Project %

Capital cost item	Hydro large store
Pre-development	1.7%
Construction	98.3%
Infrastructure	0.0%

19.2.2 Capital Cost Learning Rate Assumption and Forecast

As an established technology it is Arup’s view that there are limited learning effect for hydropower. The potential for future cost reductions may be possible though continued optimisation of the equipment and project delivery.

It should be noted that due to a lack of data from the stakeholder engagement no external views were taken into account on the future direction of cost. For LCOE modelling purposes cost is not assumed to change over time.

Table 244 Hydro 5-16MW Capital Cost Forecast 2015 – 2030, 2014 Real Prices £’000/MW

£’000/MW	2015	2020	2025	2030
Low	1,597	1,597	1,597	1,597
Medium	3,014	3,014	3,014	3,014
High	3,378	3,378	3,378	3,378

Table 245 Hydro Large Store Capital Cost Forecast 2015 – 2030, 2014 Real Prices £’000/MW

£’000/MW	2015	2020	2025	2030
Medium	3,283	3,283	3,283	3,283

19.3 Operating Cost

Operating costs for hydro plant mainly comprise of fixed and variable O&M contracts, UoS charges, insurance and labour. Table 246 and 247 below provides an overview of the operating cost assumptions used for LCOE modelling. Please note that the medium value is £63k/MW and £57k/MW for hydro 5-16MW and hydro large store respectively.

19.3.1 Operating Cost Learning Rate Assumption and Forecast

For operating costs again little useful information was available from either the stakeholders or collected via the literature review. Therefore, due to a lack of available information and credible viewpoints on the future direction of cost Arup has therefore assumed operating costs are flat.

Table 246 Hydro 5-16MW Operating Costs (Financial Close 2015), 2014 Real Prices £’000/MW

£’000s/MW	Hydro 5-16MW
Low	63
Medium	63
High	63

Table 247 Hydro Large Store Operating Costs (Financial Close 2015), 2014 Real Prices £'000/MW

£'000s/MW	Hydro Large Store
Medium	57

Table 248 Hydro 5-16MW Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Low	63	63	63	63
Medium	63	63	63	63
High	63	63	63	63

Table 249 Hydro Large Store Operating Cost Forecast 2016 – 2030, 2014 Real Prices £'000/MW

£'000s/MW	2015	2020	2025	2030
Medium	57	57	57	57

19.4 Cost Breakdown

Due to a lack of data Arup did not carry out a detailed analysis of the key drivers of cost (pre-development, construction and infrastructure). The following provides a breakdown of cost based on DECC's existing data which is also compared these to DECC's current LCOE assumptions.

Table 250 Hydro 5-16MW Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	55	55	55	55
	Construction	£/kW	2,958	2,958	2,958	2,958
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**3,014**	**3,014**	**3,014**	**3,014**
	Total opex	**£MW**	**63,184**	**63,184**	**63,184**	**63,184**
	Fixed O&M	£/MW	45,064	45,064	45,064	45,064
	Variable O&M	£/MWh	5.9	5.9	5.9	5.9
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	0	0	0	0
	UoS	£/MW	0	0	0	0
DECC Current	Pre-development	£/kW	55	55	55	55
	Construction	£/kW	3,258	3,597	3,609	3,618
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**3,313**	**3,652**	**3,664**	**3,674**
	Total opex	**£/MW**	**63,421**	**63,659**	**63,899**	**64,139**
	Fixed O&M	£/MW	45,233	45,403	45,573	45,744
	Variable O&M	£/MWh	5.9	6.0	6.0	6.0
	Insurance	£/MW	0	0	0	0
	UoS	£/MW	0	0	0	0

	Assumption	Unit	2015	2020	2025	2030
% Change	Pre-development	%	0%	0%	0%	0%
	Construction	%	-9%	-18%	-18%	-18%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-9%**	**-17%**	**-18%**	**-18%**
	Total opex	%	**0%**	**-1%**	**-1%**	**-1%**

Table 251 Hydro Large Store Cost Comparison between Arup 2015 and DECC Current, 2014 Real Prices

	Assumption	Unit	2015	2020	2025	2030
Arup 2015	Pre-development	£/kW	55	55	55	55
	Construction	£/kW	3,227	3,227	3,227	3,227
	Infrastructure	£'000	0	0	0	0
	Total capex	**£/kW**	**3,283**	**3,283**	**3,283**	**3,283**
	Total opex	**£MW**	**57,251**	**57,251**	**57,251**	**57,251**
	Fixed O&M	£/MW	25,659	25,659	25,659	25,659
	Variable O&M	£/MWh	5.9	5.9	5.9	5.9
	BSUoS	£/MWh	0.0	0.0	0.0	0.0
	Insurance	£MW	950	950	950	950
	UoS	£/MW	7,603	7,603	7,603	7,603
DECC Current	Pre-development	£/kW	55	55	55	55
	Construction	£/kW	3,554	3,924	3,937	3,947
	Infrastructure	£'000	0	0	0	0

	Assumption	Unit	2015	2020	2025	2030
	Total capex	**£/kW**	**3,609**	**3,979**	**3,992**	**4,003**
	Total opex	**£/MW**	**57,438**	**57,625**	**57,813**	**58,001**
	Fixed O&M	£/MW	25,756	25,852	25,950	26,047
	Variable O&M	£/MWh	5.9	6.0	6.0	6.0
	Insurance	£/MW	954	957	961	965
	UoS	£/MW	7,603	7,603	7,603	7,603
% Change	Pre-development	%	0%	0%	0%	0%
	Construction	%	-9%	-18%	-18%	-18%
	Infrastructure	%	-	-	-	-
	Total capex	%	**-9%**	**-18%**	**-18%**	**-18%**
	Total opex	%	**0%**	**-1%**	**-1%**	**-1%**

19.5 Technical Assumptions

Arup was not able to collect data at the plant scales required. Therefore the analysis takes into account DECC's current technical assumptions.

Table 252 Hydro 5-16MW Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	10.50	10.50	-
Availability	%	98%	98%	0.0%
Load factor (gross)	%	36%	36%	0.0%
Load factor (net)	%	35%	35%	0.0%

Table 253 Hydro Large Store Technical Assumptions

Assumption	Unit	DECC	Arup	Change (%, net)
Net Power	MW	10.50	10.50	-
Availability	%	98%	98%	0.0%
Load factor (gross)	%	45%	45%	0.0%
Load factor (net)	%	45%	45%	0.0%

The following load factors are were assumed for LCOE modelling purposes.

Table 254 Assumed Load Factor %

%	Hydro 5-16MW	Hydro Large Store
Medium, gross	35.7%	45.3%
Medium, net	35.0%	44.5%

19.6 Levelised Cost

As outlined in Section 18.2 above Arup’s dataset is based on DECC’s existing data for both hydro 5-16MW and hydro large store. The following summary tables provide a comparison between LCOE based on Arup’s new cost data, DECC’s current assumptions and discount rates. Overall, at the UK level the data indicates that a project starting in 2016 and commissioning by 2020 will have an LCOE of around 7% higher than current DECC figures. Tables 257 to 258 provide the LCOE results based on DECC’s updated hurdle rate for the technology.

Table 255 Hydro 5-16MW LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Low	54	54	54	54
Medium	84	84	84	84
High	92	92	92	92

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 256 Hydro Large Store LCOE 2016 – 2030, 2014 Real Prices* £/MWh

£/MWh	2016	2020	2025	2030
Medium	71	69	69	69

**Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results for this and the below table*

Table 257 LCOE 2016 – 2030 (Hydro Large Store), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Medium	84	84	84	84

Table 258 LCOE 2016 – 2030 (Hydro 5-16MW), 2014 Real Prices £/MWh, Updated DECC Hurdle Rates

£/MWh	2016	2020	2025	2030
Low	61	61	61	61
Medium	97	97	97	97
High	107	107	107	107

19.7 Comparison of DECC and Arup LCOE Values

Based on the learning rate forecast, capital and operating cost profiles Arup has calculated LCOE for a hydro 5-16MW and large store reference plant for a project starting in 2016 and commissioning (i.e. becoming operational in a specific year) in 2020, 2025 and 2030. The following LCOE ranges are based on the low, medium and high capital cost estimates and use DECC's current hurdle assumptions.

Table 259 Hydro 5-16MW Comparison Arup vs. DECC, 2014 Real Prices £/MWh

£/MWh	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Low	54	54	60	60	-9.4%	-9.4%
Medium	84	84	95	95	-11.2%	-11.2%
High	92	92	103	103	-10.7%	-10.7%

Table 260 Hydro Large Store Comparison Arup vs. DECC, 2014 Real Prices £/MWh

%	Arup 2016	Arup 2020	DECC 2016	DECC 2020	% Change (2016)	% Change (2020)
Medium	71	69	77	78	-8.8%	-11.6%

Appendix A

Stakeholder Survey

A1 Stakeholder Survey

The following spreadsheets provides are copies of the data collection survey issued during Phase One and Phase Two of the Study.

Phase One Data Collection Questionnaire

Section A - Project Specific Information

General project questions	Response
Renewable technology, *please select technology family from drop-down*	*Please select*
Name or title of project	
Location of project *(e.g. England, Scotland, Wales, Northern Ireland, remote islands)*	*Please select*
Please indicate if data provided is provide for a range or individual projects, *please select from drop-down*	*Please select*
Stage of project *(earlier than pre-development, pre-development, financial close, operation start, generating)*	
Operation start year (expected or actual)	
Size that specific project costs are provided for MW(e) net (please provide net electrical capacity) *(if not supplying data for an individual project, please provide an average and range of size of your projects*	
How is the land structured? *(lease, freehold, rented)*	
Is the project a new built asset / or retro-fit?	
What procurement / contracting strategy is in place? *(e.g. full engineering, procurement and construction contract, EPC wrap or individual sub-contracts)*	
What is the approximate distance in km to the grid? Is the project connected to the electricity distribution or transmission grid	
Are there any substantial non-typical costs included in your cost estimates (e.g. brown field remediation works)? *If so what % of the EPC cost is made up of these non-typical costs?*	
Is the data provided below commercially confidential *(please indicate which aspects of the data are confidential and why)*	
Has the information been submitted to DECC previously? *(please indicate date and format e.g. cost data as below supplied to Arup in 2010 OR general overview of the project supplied as part of the RO Banding consultation)*	
If this data has been submitted previously please indicate if and how it has changed *(e.g. Operating costs have fallen / increased by 1% since 2010).* **If it was not submitted to DECC previously, please indicate why this was the case** *(e.g. it is a new project).*	

Cost items	Unit	Response / comment	Capacity MW	Cost	Time Years	%	Future cost 2020	Future cost 2030
PLANT ASSUMPTIONS								
Plant capacity MW(e) *gross (please provide gross electrical capacity incl auxiliary load)*	[MWe]	**Primary:** please comment on plant capacity						
Plant capacity MW(e) *net (please provide net electrical capacity excl auxiliary load)*	[MWe]	**Primary:** please comment on plant capacity						
Connection capacity *(what is the connection capacity)*	[MW]	**Primary:** Please comment on connection capacity						
CURRENT ASSUMPTIONS								
Currency, please select	[£,$,€]	**Primary:** please indicate cost currency, preference is for £/sterling		*Please select*				
PRE – DEVELOPMENT COST (Please note excludes land costs, property and business rates tax costs, rental and community benefit payments. These items are required separately under additional data)								
To what year do the following costs apply? (e.g. 2014)	[Yr]	**Primary:** please indicate the cost base year						
Pre-licensing cost	[£]	**Primary:** please comment on what is included in pre-licensing cost						
Technical development cost *(including design selection)*	[£]	**Primary:** please comment on what is included within technical development cost						
Planning cost *(including regulatory costs, licensing, public enquiry, 'local community engagement' costs)*	[£]	**Primary:** please explain what is included / excluded from planning costs						
Timescale for pre-development *(total pre-development period including pre-licensing, licensing, public enquiry)*	[Yrs.]	**Primary:** please provide comment on pre-development timescale (e.g. 2.5 years)						
Is a contingency included within the above pre-development costs? If so what % of the above cost is contingency? (e.g. 10% of £1m (£100k contingency, £900k pre-development cost) / If no contingency is included what would the typical % included on top of pre-development cost be. *(e.g. for potential cost overrun and development uncertainty)*	[%]	**Primary:** please comment on the level of contingency included within the pre-development cost. If not included please indicate what level of contingency would typically be assumed for this phase.						
Distribution of the costs over the pre-development period *(e.g. 50% cost upfront and rest straight line, straight line for full pre-development period or straight line with 50% of cost back-ended)*	[%]	**Primary:** please provide information on the distribution of project pre-development costs: 2015 25%, 2016 35%, 2017 40%						
CONSTRUCTION COST (Please note excludes land costs, property and business rates tax costs, rental and community benefit payments. These items are required separately under additional data)								
To what year do the following costs apply? (e.g. 2014)	[Yr]	**Primary:** Please provide the cost base year						
Capital (overnight) cost ***[please provide either total cost or total cost per kW installed]*** *The cost item covers the projected design, procurement and construction costs e.g. EPC costs if applicable. It should include the full capital cost EXCLUDING interest costs during construction and excluding land costs).* *The below costs should be listed separately if available, otherwise please indicate if they have been included in this item.*	[£ or £/kW]	**Primary:** Please indicate what is included within the total capital cost. For example: engineering design; procurement; construction; equipment included e.g. generation plant, processing equipment etc.						
Owner's costs ***[please provide total cost]*** *(Includes procurement cost, project management - owner's engineer etc.)*	[£]	Please indicate what is included within owner's costs. For example: procurement; project management owner's engineer						
Grid connection costs ***[please provide total cost]*** *(e.g. exclude pre-connection securities, but include any upfront connection payment)*	[£]	**Primary:** please comment on grid costs. Can you please indicate km of overhead / underground cable and km of gas pipeline (if applicable).						
Substation and transformer costs ***[please provide total cost]***	[£]	Please comment on the cost of substation / transformer station.						
Other infrastructure costs ***[please provide total cost]*** *(if applicable e.g. water, roads, sites works etc.)*	[£]	**Primary:** please indicate where other infrastructure costs are derived from. For example access roads, site works and security Primary:						
Is a contingency included within the above construction costs? If so what % of the above cost is contingency? (e.g. 10% of £10m (£1m contingency, £9m capex) / If no contingency is included what would the typical % included on top of capex cost be. *(e.g. for potential cost overrun and development uncertainty)*	[%]	**Primary:** please comment on the level of contingency included within construction cost. If not included please indicate what level of contingency would typically be assumed for this phase.						
Construction time period	[Yrs.]	**Primary:** please provide commentary on the construction timescale, what does the period cover?						
Distribution of costs over the construction period *(e.g. 50% costs upfront and rest straight line, straight line for full construction period or straight line with 50% of costs back-ended)*	[%]	**Primary:** please provide distribution of total costs over the construction period. For example 2016 50%, 2017 50%						
CHP equipment costs ***[please provide total cost]*** *(please separate CHP costs if data is available)*	[£]	**Primary:** if relevant please indicate the type and cost of the CHP engine. Have these costs been included in the above cost items?						
Cost of other equipment for example, feedstock processing and preparation equipment ***[please provide total cost]***	[£]	**Primary:** if relevant please provide indicate what equipment and its cost e.g. feedstock processing and preparation equipment. Have these costs been included in the above cost items?						
Boiler equipment costs ***[please provide total cost]*** *(please separate boiler costs if data is available)*	[£]	**Primary:** if relevant please indicate the cost of the boiler. Have these costs been included in the above cost items?						
Construction cost comment	[Text]	If only the total capital cost has been provided can you please indicate what costs are included / excluded						

OPERATIONAL COST (Please note excludes land costs, property and business rates tax costs, rental and community benefit payments. These items are required separately under additional data) (Please provide the following operating cost data on a unit cost basis – i.e. per kW/ MW or kWh/ MWh as appropriate. If different from unit in 'column D' please indicate the unit your cost figures are reported in)								
To what year do the following costs apply? (e.g. 2014)	[Yr]	**Primary:** please provide the cost base year						
Fixed O&M cost *(Includes operating labour costs, planned and unplanned maintenance, lifecycle capital renewable cost)*	[£/MW/a]	**Primary:** please indicate what is included within fixed O&M cost. For example: labour, planned maintenance and lifecycle replacement.						
Variable O&M cost	[£/MWh]	**Primary:** please indicate what is included within variable O&M cost. For example planned and unplanned maintenance, water and chemical usage						
Insurance cost	[£/MW/a]	**Primary:** please provide commentary on insurance costs						
Operational cost comment	[Text]	If only the total operational cost has been provided can you please indicate what costs are included / excluded						
Connection and UoS charge costs *(e.g. TNUoS, BSUoS, DUoS and OFTO)*								
TNUoS - cost *(payment for use of the Transmission Network and including OFTO for offshore wind)*	[£/MW/a]	**Primary**						
BSUoS - cost *(charge for the balancing actions of National Grid)*	[£/MW/a]	**Primary**						
DUoS - cost *(charge for operating and maintaining local distribution network)*	[£/MW/a]	**Primary**						
DECOMMISSIONING AND WASTE COSTS								
Waste disposal cost *(i.e. waste management and disposal costs during operational period)*	[£/MWh/a]	**Primary:** please indicate what is disposed of under waste cost.						
Decommissioning spend *(i.e. decommission spend e.g. provisions to cover decommissioning expenditure after operation)*	[£/MWh/a or £/MW/a]	**Primary:** please indicate decommission spend and what period it is likely to occur in.						
Waste disposal cost *(i.e. waste management and disposal costs post-operation)*	[£/MW/a]	Please indicate expected waste disposal cost post-operation.						
Decommissioning spend *(i.e. post-operation)*	[£/MW/a]	Please indicate the expected decommission cost spend post-operation.						
Expected decommissioning period and timing	[Yrs.]	**Primary:** please indicate number of years and likely timing of decommissioning						

TECHNICAL ASSUMPTIONS								
What proportion of electricity generation is for parasitic load and export.	[%]	**Primary:** please indicate what proportion of generation is for parasitic load						
Plant availability during full annual operation % (Availability is defined as the total time proportion that a plant is able to produce electricity over a full year)	[%]	**Primary:** please indicate.						
Average annual reduction in plant availability (if applicable) %	[%]	**Primary:** by what % do you expect plant availability to decline over time What is the expected timing and impact of major refurbishment work on availability?						
Average annual expected load factor *(Defined as average operating hours at full load equivalent divided by hours per year)*	[%]	**Primary:** please provide average annual load factor. In addition, if available what load factor improvements are expected over time i.e. taking into account different commissioning dates, maintenance etc. For example offshore wind: 2016 (36%), 2017 (38%) and 2018 (40%)						
Expected reduction in average annual load factor (if applicable)	[%]	By what % do you expect plant load factor to decline over time.						
Plant operational life (technical life) i.e. expected maximum operational life	[Yrs.]	**Primary**						
TECHNOLOGIES WHICH REQUIRE FUEL INPUT(S)								
Fuel input type: e.g. biomass generation (virgin wood, waste wood, wood pellets); ACT (biomass, municipal waste treated to derive SRF/RDF).	[Text]	**Primary:** please indicate fuel input type						
Fuel type mix %	[%]	**Primary:** please indicate fuel mix. For example, 20% wood chip, 80% SRF						
What is the total tonnage of each fuel type expected to be used per year and the extended 5-year mix.	[Tons]							
What is the average renewable content of each fuel (*Please indicate either in % mass or % energy content)*	[% mass / % energy content]	**Primary:** please indicate average renewable content of each fuel, the % mass or % energy content						
Fuel type under contract	[Tons]	**Primary:** please indicate the fuel type under contract						
What is the length of each fuel supply contract in place?	[Yrs.]							
Are there any fuels not under contract?	[Text]							
What is the gate fee / price of each type of fuel *e.g. ACT cost before/after waste processing £/MWh or £/ODT depending on the type of fuel.*	[£/MWh]	**Primary:** please report cost in £/MWh, if not available £/ODT as appropriate. Please indicate if price before or after processing.						
What is your expectation for change in gate fees / price to change over time?	[£/MWh]	**Primary:** please report cost in £/MWh, if not available £/ODT is also suitable. Please indicate if price before or after processing.						
Net efficiency (LHV) %	[%]	**Primary:** please report the lower heating value efficiency of changing fuel input into electrical output, full condensing output						
Net efficiency (HHV) %	[%]	**Primary:** please report the higher heating value efficiency of changing fuel input into electrical output, full condensing output						
Expected annual change in efficiency	[%]	**Primary:** Is any change in efficiency expected over time (yes/no)? If yes, please report the expected annual change in efficiency.						

CHP ASSUMPTIONS								
Average thermal output in MW thermal	[MWth]	**Primary.**						
What is the installations average heat to power ratio? (e.g. 2:1; 20MW heat, 10MW electricity)	[No.]	**Primary:** please indicate heat to power ratio						
FINANCIAL ASSUMPTIONS								
Expected economic life (years) - *expected period that plant will remain an economically viable operation*	[Yrs.]	**Primary.**						
Required IRR (%) - *required rate of return on the project. Please state if the figure is pre or post-tax, in nominal or real terms.*	[%]	**Primary.**						
Risk perception of the project - *low, medium or high*	[Text]	Please indicate whether the project is of a low, medium or high risk rating						
Type of finance - *expected level of equity (%) or debt (%) financed*	[Text / %]	If debt financed can you please provide information on the average interest rate over the construction and operation periods? What is the tenor of the loan?						
ADDITIONAL DATA (Excluded from pre-development, construction and operation costs above)								
Land costs including land purchase but excluding mortgage cost and rental fees *(Excluded from total capital costs above)*	[£]	**Primary.**						
On-going property and business rates tax cost	[£/MW/a]	**Primary.**						
On-going property rental cost	[£/MW/a]	**Primary.**						
Community benefit payments	[£/MW/a]	**Primary.**						
To what extent do you expect to meet the good quality CHP (CHP QA) standards?	[%]							

Advanced Conversion Technology ('ACT') including pyrolysis and gasification	Response
Who has manufactured your ACT equipment?	
What process does the ACT generator operate? *(e.g. fluidisation, plasma arc, entrained etc.)*	*Please select*
Does the information provided under 'Part A' include / exclude syngas cleaning or scrubbing equipment costs? What equipment is being used and what is the total cost of the equipment? *(e.g. particularly relating to the removal of tars or dust)*	
Input into the ACT chamber? *(applies to gasification only e.g. is it blown with oxygen, air or steam)*	
Does the ACT process include a syngas cooling phase? Is there heat recovered?	
Is the ACT plant connected to a secondary generation plant for electricity generation? *(e.g. is syngas used as an input into a gas turbine, CHP, steam turbine, combustion chamber etc.)*	
Is the syngas being used for (or possibly in the future) another process other than electricity generation? *(e.g. fuel, chemical input or product production)*	
Can you please indicate the expected calorific value of each fuel(s) being produced/used, MJ/cbm	

Offshore wind	Response
Which round is your offshore project attached to? *(e.g. Round 2, Round 3)*	
What approximate distance is shore from your project (km)?	
What is the approximate average sea depth where your project is located (m)?	
What is the approximate distance of the project to your supply port (km)?	
What type of foundation is being deployed? *(e.g. jacket, monopole?)*	
What technology is being used in the project? *(e.g. turbines manufacturer?)*	
What is the average turbine size MW	
Are there any constraints in the supply chain *(e.g. supply of turbines, availability of ships?)*	

Biomass CHP	Response
What revenue do you receive from heat sales £/MWh th	
What is the length of the heat contract in place (years)	
What is the grade of heat supplied (temperature) and steam (bar)	
Is there heat storage onsite (yes/no) if so what is the capacity (cbm)	
What is the capex and opex of the heat storage system	

Solar	Response
Is the solar installation either ground mounted or building mounted	*Please select*
What technology is being used in the project? *(e.g. panel manufacturer?, thin-film, crystalline panels, building integrated?)*	
What country is the solar technology from *(e.g. China, Germany)*	
Can you please indicate the % proportion of each of the following costs toward total project capital cost:	
- Panels	
- Inverter	
- Cabling	
- Mounting (ground / roof)	
- Other costs	
What is the average annual expected level of degradation %	

Onshore wind	Response
What approximate distance is your development from the grid (km)?	
What technology is being used in the project? *(e.g. Siemens turbines?)*	
What is the average turbine size MW	
Are there any constraints in the supply chain	

Section B - General information

Please read and answer Section B with specific project details taking into account the following:

- General information about your portfolio of projects
- Expectations of future change in the cost for pre-development, construction, operational and financing costs
- Section A attempts to collate point estimates for individual cost items. Please provide below commentary on expectations for change in each cost category

Information about your company

Are you a developer, investor or operator?		
Amount of technology/ installed capacity deployed by you globally to date:		[MW]
Amount of technology/ installed capacity deployed by you in UK to date:		[MW]
Amount of technology/ installed capacity and in development by you in UK currently. What is in your immediate pipeline?		[MW]
Amount of technology / installed capacity expected to be developed by you in the UK. How much new installed capacity do you expect to deploy between 2015 and 2020, and between 2020 and 2030?		[MW]

General questions on your portfolio of renewable generation projects	**Response**
What do you consider the key drivers to be behind:	
- **Pre-development costs** *(e.g. planning hurdles, licensing, technology, environmental, etc.)*	
- **Construction costs** *(e.g. steel, exchange rates, energy costs, labour costs, other)*	
- **Operational costs** *(e.g. exchange rates, fuel costs, labour costs, other)*	
What are your expectations of the likely change in cost <u>in real terms</u> between 2015 to 2020 and 2030? *(e.g. please provide an overall % estimate for each category and your assumptions behind this e.g. 'in our discounted cashflow modelling we assume fuel costs will increase by 5%')*	
- **Pre-development costs** *(e.g. planning hurdles, licensing, technology, environmental, etc.)*	
- **Construction costs** *(e.g. steel, exchange rates, energy costs, labour costs, other)*	
- **Operational costs** *(e.g. exchange rates, fuel costs, labour costs, other)*	
- **Required IRR** *(e.g. expected % point change in IRR)*	

Phase Two Data Collection Questionnaire

Section A - Project Specific Information

General project questions	Response
Renewable technology, *please select technology family from drop-down*	*Please select*
Name or title of project	
Location of project *(e.g. England, Scotland, Wales, Northern Ireland, remote islands)*	*Please select*
Please indicate if data provided is provide for a range or individual projects, *please select from drop-down*	*Please select*
Stage of project *(earlier than pre-development, pre-development, financial close, operation start, generating)*	
Operation start year (expected or actual)	
Size that specific project costs are provided for MW(e) net (please provide net electrical capacity (for CHP please quote values for full-condensing power only mode) *(if not supplying data for an individual project, please provide an average and range of size of your projects and indicate the number of projects)*	
How is the land structured? *(lease, freehold, rented)*	
Is the project a new built asset / or retro-fit?	
What procurement / contracting strategy is in place? *(e.g. full engineering, procurement and construction contract, EPC wrap or individual sub-contracts)*	
What is the approximate distance in km to the grid? Is the project connected to the electricity distribution or transmission grid?	
Are there any substantial non-typical costs included in your cost estimates (e.g. brown field remediation works)? *If so what % of the EPC cost is made up of these non-typical costs?*	
Is the data provided below commercially confidential? *(please indicate which aspects of the data are confidential and why)*	
Has the information been submitted to DECC previously? *(please indicate date and format e.g. cost data as below supplied to Arup in 2010 OR general overview of the project supplied as part of the RO Banding consultation)*	
If this data has been submitted previously please indicate if and how it has changed *(e.g. Operating costs have fallen / increased by 1% since 2010)?* **If it was not submitted to DECC previously, please indicate why this was the case** *(e.g. it is a new project?)*	

Cost items	Unit	Response / comment	Capacity	Cost	Time	%	Future cost	
			MW/MWh		Years		2020	2030
PLANT ASSUMPTIONS								
Plant capacity MW(e) *gross (please provide gross electrical capacity incl auxiliary load)*	[MWe]	**Primary:** please comment on plant capacity. [For CHP please can you quote values for a full-condensing power only mode]						
Plant capacity MW(e) *net (please provide net electrical capacity excl auxiliary load)*	[MWe]	**Primary:** please comment on plant capacity [For CHP please can you quote values for a full-condensing power only mode]						
Connection capacity *(what is the connection capacity)*	[MW]	**Primary:** Please comment on connection capacity						
CURRENT ASSUMPTIONS								
Currency, please select	[£,$,€]	**Primary:** please indicate cost currency, preference is for £/sterling		*Please select*				
PRE – DEVELOPMENT COST (Please note excludes land costs, property and business rates tax costs, rental and community benefit payments. These items are required separately under additional data)								
To what year do the following costs apply? (e.g. 2014)	[Yr]	**Primary:** please indicate the cost base year (e.g. real 2014 prices)						
Pre-licensing cost	[£]	**Primary:** please comment on what is included in pre-licensing cost						
Technical development cost *(including design selection)*	[£]	**Primary:** please comment on what is included within technical development cost						
Planning cost *(including regulatory costs, licensing, public enquiry, 'local community engagement' costs)*	[£]	**Primary:** please explain what is included / excluded from planning costs						
Timescale for pre-development	[Months]	**Primary:** please provide comment on pre-development timescale (e.g. 2.5 years)						
Is a contingency included within the above pre-development costs? If so what % of the above cost is contingency? (e.g. 10% of £1m (£100k contingency, £900k pre-development cost) / If no contingency is included what would the typical % included on top of pre-development cost be. *(e.g. for potential cost overrun and development uncertainty)*	[%]	**Primary:** please comment on the level of contingency included within the pre-development cost. If not included please indicate what level of contingency would typically be assumed for this phase.						
Distribution of the costs over the pre-development period *(e.g. 50% cost upfront and rest straight line, straight line for full pre-development period or straight line with 50% of cost back-ended)*	[%]	**Primary:** please provide information on the distribution of project pre-development costs: 2015 25%, 2016 35%, 2017 40%						

CONSTRUCTION COST (Please note excludes land costs, property and business rates tax costs, rental and community benefit payments. These items are required separately under additional data)		
To what year do the following costs apply? (e.g. 2014)	[Yr]	**Primary:** Please provide the cost base year (e.g. real 2014 prices)
Capital (overnight) cost *[please provide either total cost or total cost per kW installed]* *The cost item covers the projected design, procurement and construction costs e.g. EPC costs if applicable. It should include the full capital cost EXCLUDING interest costs during construction and excluding land costs).* *The below costs should be listed separately if available, otherwise please indicate if they have been included in this item.*	[£ or £/kW]	**Primary:** Please indicate what is included within the total capital cost. For example: engineering design; procurement; construction; equipment included e.g. generation plant, processing equipment etc. [For CHP please can you quote values for a full-condensing power only mode]
Owner's costs *[please provide total cost]* *(Includes procurement cost, project management - owner's engineer etc.)*	[£]	Please indicate what is included within owner's costs. For example: procurement; project management owner's engineer
Grid connection costs *[please provide total cost]* *(e.g. exclude pre-connection securities, but include any upfront connection payment)*	[£]	**Primary:** please comment on grid costs. Can you please indicate km of overhead / underground cable and km of gas pipeline (if applicable).
Substation and transformer costs *[please provide total cost]*	[£]	Please comment on the cost of substation / transformer station.
Other infrastructure costs *[please provide total cost]* *(if applicable e.g. water, roads, sites works etc.)*	[£]	**Primary:** please indicate where other infrastructure costs are derived from. For example access roads, site works and security
Is a contingency included within the above construction costs? If so what % of the above cost is contingency? (e.g. 10% of £10m (£1m contingency, £9m capex) / If no contingency is included, what would the typical % included on top of capex cost be? *(e.g. for potential cost overrun and development uncertainty)*	[%]	**Primary:** please comment on the level of contingency included within construction cost. If not included please indicate what level of contingency would typically be assumed for this phase.
Construction time period	[Months]	**Primary:** please provide commentary on the construction timescale, what does the period cover?
Distribution of costs over the construction period *(e.g. 50% costs upfront and rest straight line, straight line for full construction period or straight line with 50% of costs back-ended)*	[%]	**Primary:** please provide distribution of total costs over the construction period. For example 2016 50%, 2017 50%
CHP equipment costs *[please provide total cost]* *(please separate CHP costs if data is available)*	[£]	**Primary:** please indicate the type and incremental cost of the CHP. Have these costs been included in the above cost items?
Cost of other equipment for example, feedstock processing and preparation equipment *[please provide total cost]*	[£]	**Primary:** if relevant please provide indicate what equipment and its cost e.g. feedstock processing and preparation equipment. Have these costs been included in the above cost items?
Boiler equipment costs *[please provide total cost]* *(please separate boiler costs if data is available)*	[£]	**Primary:** if relevant please indicate the cost of the boiler. Have these costs been included in the above cost items?
Construction cost comment	[Text]	If only the total capital cost has been provided can you please indicate what costs are included / excluded

OPERATIONAL COST (Please note excludes land costs, property and business rates tax costs, rental and community benefit payments. These items are required separately under additional data) (Please provide the following operating cost data on a unit cost basis – i.e. per kW/ MW or kWh/ MWh as appropriate. If different from unit in 'column D' please indicate the unit your cost figures are reported in)								
To what year do the following costs apply? (e.g. 2014)	[Yr]	**Primary:** please provide the cost base year (e.g. real 2014 prices)						
Fixed O&M cost *(Includes operating labour costs, planned and unplanned maintenance, lifecycle capital renewable cost)*	[£/MW/a]	**Primary:** please indicate what is included within fixed O&M cost. For example: labour, planned maintenance and lifecycle replacement [For CHP please can you quote values for a full-condensing power only mode]						
Variable O&M cost	[£/MWh]	**Primary:** please indicate what is included within variable O&M cost. For example planned and unplanned maintenance, water and chemical usage [For CHP please can you quote values for a full-condensing power only mode]						
Insurance cost	[£/MW/a]	**Primary:** please provide commentary on insurance costs [For CHP please can you quote values for a full-condensing power only mode]						
Operational cost comment	[Text]	If only the total operational cost has been provided can you please indicate what costs are included / excluded						
Connection and UoS charge costs *(e.g. TNUoS, BSUoS, DUoS and OFTO)*								
TNUoS - cost *(payment for use of the Transmission Network and including OFTO for offshore wind)*	[£/MW/a]	**Primary** [For CHP please can you quote values for a full-condensing power only mode]						
BSUoS - cost *(charge for the balancing actions of National Grid)*	[£/MW/a]	**Primary** [For CHP please can you quote values for a full-condensing power only mode]						
DUoS - cost *(charge for operating and maintaining local distribution network)*	[£/MW/a]	**Primary** [For CHP please can you quote values for a full-condensing power only mode]						

DECOMMISSIONING AND WASTE COSTS								
Waste disposal cost *(i.e. waste management and disposal costs during operational period)*	[£/MWh/a]	**Primary:** please indicate what is disposed of under waste cost. [For CHP please can you quote values for a full-condensing power only mode]						
Decommissioning spend *(i.e. decommission spend e.g. provisions to cover decommissioning expenditure after operation)*	[£/MWh/a or £/MW/a]	**Primary:** please indicate decommission spend and what period it is likely to occur in. [For CHP please can you quote values for a full-condensing power only mode]						
Waste disposal cost *(i.e. waste management and disposal costs post-operation)*	[£/MW/a]	Please indicate expected waste disposal cost post-operation. [For CHP please can you quote values for a full-condensing power only mode]						
Decommissioning spend *(i.e. post-operation)*	[£/MW/a]	Please indicate the expected decommission cost spend post-operation. [For CHP please can you quote values for a full-condensing power only mode]						
Expected decommissioning period and timing	[Months]	**Primary:** please indicate number of years and likely timing of decommissioning						

TECHNICAL ASSUMPTIONS								
What proportion of electricity generation is for parasitic load and export. Please also state what percentage of power is used for local use?	[%]	**Primary:** please indicate what proportion of generation is for parasitic load and export.						
Plant availability during full annual operation % (Availability is defined as the total time proportion that a plant is able to produce electricity over a full year)	[%]	**Primary:** please indicate.						
Average annual reduction in plant availability (if applicable) %	[%]	**Primary:** by what % do you expect plant availability to decline over time What is the expected timing and impact of major refurbishment work on availability?						
Average annual expected load factor *(Defined as average operating hours at full load equivalent divided by hours per year)*	[%]	**Primary:** please provide average annual load factor. In addition, if available what load factor improvements are expected over time i.e. taking into account different commissioning dates, maintenance etc. For example offshore wind: 2016 (36%), 2017 (38%) and 2018 (40%)						
Expected reduction in average annual load factor (if applicable)	[%]	By what % do you expect plant load factor to decline over time.						
Plant operational life (technical life) i.e. expected maximum operational life	[Yrs.]	**Primary**						

TECHNOLOGIES WHICH REQUIRE FUEL INPUT(S)		
Fuel input type: *e.g. energy from waste (biomass, municipal waste treated to derive SRF/RDF), anaerobic digestion (slurry, farm waste, waste food).*	[Text]	**Primary:** please indicate fuel input type
Fuel type mix %	[%]	**Primary:** please indicate fuel mix. For example, 20% wood chip, 80% SRF
What is the total tonnage of each fuel type expected to be used per year and the extended 5-year mix.	[Metric tonnes]	
What is the average renewable content of each fuel? *(Please indicate either in % mass or % energy content)*	[% mass / % energy content]	**Primary:** please indicate average renewable content of each fuel, the % mass or % energy content
Indicate the higher and lower calorific value of each fuel used in the fuel mix	[MJ/kg]	
Fuel type under contract	[Metric tonnes]	**Primary:** please indicate the fuel type under contract
What is the length of each fuel supply contract in place?	[Yrs.]	
Are there any fuels not under contract?	[Text]	
What is the gate fee / price of each type of fuel *e.g. ACT cost before/after waste processing £/MWh or £/ODT ('oven dried tons') depending on the type of fuel. Please indicate a positive number for revenue and a negative value for a cost.*	[£/MWh]	**Primary:** please report cost in £/MWh, if not available £/ODT ('oven dried tons') as appropriate. Please indicate if price before or after processing.
What is your expectation for change in gate fees / price to change over time?	[£/MWh]	**Primary:** please report cost in £/MWh, if not available £/ODT ('oven dried tons') is also suitable. Please indicate if price before or after processing.
Net efficiency (LHV) %	[%]	**Primary:** please report the lower heating value efficiency of changing fuel input into electrical output, full condensing output
Net efficiency (HHV) %	[%]	**Primary:** please report the higher heating value efficiency of changing fuel input into electrical output, full condensing output
Expected annual change in efficiency	[%]	**Primary:** Is any change in efficiency expected over time (yes/no)? If yes, please report the expected annual change in efficiency.

CHP ASSUMPTIONS								
What proportion of electricity is used locally?	[%]	**Primary:** please indicate what proportion of generation is used locally						
What is the average useful heat output in MW thermal?	[MWth]	**Primary.**						
What is the installations average heat to power ratio? (e.g. 2:1; 20MW heat, 10MW electricity)	[No.]	**Primary:** please indicate heat to power ratio						
What is the length of the heat contract in place?	[Months]							
To what extent do you expect to meet the good quality CHP (CHPQA) standards? (QPO/TPO as a percentage)	[%]							
What are the grades of heat supplied (hot water / steam, temperature and pressure)?	[Text/%]							
How would the plant perform in power only mode?	kW, MW, MWh							
What Heat:Power Ratio do you expect to operate?	HPR							
Please provide your "z-ratio".	[No.]							

FINANCIAL ASSUMPTIONS									
Expected economic life (years) - *expected period that plant will remain an economically viable operation*	[Yrs.]	**Primary.**							
Required 'Project' IRR (%) - *required rate of return on the project (not equity). Please state if the figure is pre or post-tax, in nominal or real terms.*	[%]	**Primary.**							
What is your effective tax rate? (%) - *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.*	[%]	**Primary.**							
Risk perception of the project - *low, medium or high*	[Text]	Please indicate whether the project is of a low, medium or high risk rating							
Type of finance - *expected level of equity (%) or debt (%) financed*	[Text / %]	If debt financed can you please provide information on the average interest rate over the construction and operation periods? What is the tenor of the loan?							
ADDITIONAL DATA (Excluded from pre-development, construction and operation costs above)									
Land costs including land purchase but excluding mortgage cost and rental fees *(Excluded from total capital costs above)*	[£]	**Primary.** [For CHP please can you quote values for a full-condensing power only mode]							
On-going property and business rates tax cost	[£/MW/a]	**Primary.** [For CHP please can you quote values for a full-condensing power only mode]							
On-going property rental cost	[£/MW/a]	**Primary.** [For CHP please can you quote values for a full-condensing power only mode]							
Community benefit payments	[£/MW/a]	**Primary.** [For CHP please can you quote values for a full-condensing power only mode]							

Section A - Technology Specific Information

Please answer the following questions in relation to a specific technology

Dedicated biomass	Response
If the heat is used on-site, what technology would you have used to generate the heat if bio-CHP is not available? *(e.g. XMW gas boiler, oil boiler,…)*	
What revenue do you receive from locally sold heat £/MWh? What is the steam temperature and pressure? *(e.g. total revenue and £/MWh th)*	
How is generated heat used on-site?	

Co-firing/ biomass conversion additional questions	Response
What percentage biomass can/do you co-fire in terms of fuel input (lower and higher calorific value)?	
What would the capital cost (total or per MW) be for converting a co-firing station into a dedicated biomass station? Would there be any additional operating costs?	
Excluding on-going feedstock costs are there any additional operating costs?	
Do the costs provided involve major refubishment of the plant? What is included in the conversion cost? Does this include a major refurbishment of the coal plant? *(e.g. expenditure on new boilers, mills, new storage, transportation and handling of biomass)*	

EfW / EfW CHP	Response
What is the main feedstock used at your plant? *(please provide details on feedstock opposite):*	*Feedstock 1*
	Feedstock 2
	Feedstock 3
If the heat is used on-site, what technology would you have used to generate the heat if bio-CHP was not available? *(e.g. XMW gas boiler, oil boiler,…)*	
To what extent do you expect to meet the good quality CHP (CHP QA) standards? *(these affect the degree of RO support)*	
What heat to power ratio will the installation have? *(e.g. 2:1; 20MW heat, 10MW electricity)*	
What revenue do you receive from locally sold heat £/MWh? What is the steam temperature and pressure? *(e.g. total revenue and £/MWh th)*	
How is generated heat used on-site?	

AD / AD CHP	Response
Which company has manufactured your AD equipment?	
What is the main feedstock into the AD chamber?	
What percentage (if any) of dedicated biomass fuel is used in your feedstock? *(e.g. maize, miscanthus etc)*	
Is the AD plant connected to a secondary generation plant for electricity generation?	
Does the information provided under 'Part A' include / exclude gas cleaning or scrubbing equipment costs? What equipment is being used and what is the total cost of the equipment?	
Can you please indicate the expected calorific value of each fuel(s) being used in the AD process, MJ/cbm?	
What percentage (if any) of dedicated biomass fuel is used in your feedstock (e.g. maize, miscanthus etc)?	
How is generated heat used on-site?	

Landfill	Response
What type of power production equipment do you use? *(e.g. gas turbine, gas engine etc.)*	
What is the average calorific value of the gas produced at your site(s) MJ/cbm?	
How old is your landfill site?	
How is the output from your landfill site expected to decline over time? What is the expected rate of decline?	

Sewage gas	Response
Which company manufactured your sewage gas equipment?	
Is the sewage gas plant connected to a secondary generation plant for electricity generation?	
What is the average calorific value of the gas produced at your site(s) MJ/cbm?	
How is generated heat used on-site?	

Major refurbishment or repowering	Response
If you could be involved in a major refurbishment or repowering project for a renewables installation – what technology is this in? *(e.g. Hydro)*	
What would life extension to the installation be? How would its output be affected?	
What would the capital cost (total or per MW) be for this major refurbishment of repowering? What would the on-going operating costs be post-refurbishment or re-powering?	
What % increase in power generation volume (MWh) do you expect to achieve following repower?	

Tidal / Wave	Response
Are the costs provided realised or forecast cost?	
What is the approximate distance to shore from your project (km)?	
What is the approximate average sea depth where your project is located (m)?	
What is the approximate distance of the project to your supply port (km)?	
What technology is being used in the project?	
Please provide data on the mean energy available at the project resource site. *(For wave, kW/m of wave front, or tidal stream mean peak tidal flow in ms-2).*	
Project resource: please provide data on the mean energy available at the project resource site. *(For wave, kW/m of wave front. For tidal stream mean peak tidal flow in ms-2)*	
Are there any constraints in the supply chain *(e.g. availability of ships, parts etc.)*	

Section B - General information

Please read and answer Section B with specific project details taking into account the following:

- General information about your portfolio of projects
- Expectations of future change in the cost for pre-development, construction, operational and financing costs
- Section A attempts to collate point estimates for individual cost items. Please provide below commentary on expectations for change in each cost category

Information about your company

Are you a developer, investor or operator?		
Amount of technology/ installed capacity deployed by you globally to date:		[MW]
Amount of technology/ installed capacity deployed by you in UK to date:		[MW]
Amount of technology/ installed capacity and in development by you in UK currently. What is in your immediate pipeline?		[MW]
Amount of technology / installed capacity expected to be developed by you in the UK. How much new installed capacity do you expect to deploy between 2015 and 2020, and between 2020 and 2030?		[MW]

General questions on your portfolio of renewable generation projects	**Response**
What do you consider the key drivers to be behind:	
- **Pre-development costs** *(e.g. planning hurdles, licensing, technology, environmental, etc.)*	
- **Construction costs** *(e.g. steel, exchange rates, energy costs, labour costs, other)*	
- **Operational costs** *(e.g. exchange rates, fuel costs, labour costs, other)*	
What are your expectations of the likely change in cost <u>in real terms</u> between 2015 to 2020 and 2030? *(e.g. please provide an overall % estimate for each category and your assumptions behind this e.g. 'in our discounted cashflow modelling we assume fuel costs will increase by 5%')*	
- **Pre-development costs** *(e.g. planning hurdles, licensing, technology, environmental, etc.)*	
- **Construction costs** *(e.g. steel, exchange rates, energy costs, labour costs, other)*	
- **Operational costs** *(e.g. exchange rates, fuel costs, labour costs, other)*	
- **Required IRR** *(e.g. expected % point change in IRR)*	

Appendix B

Load Factor Indexes

B1 Load Factor Indexes

The following tables provide a summary of the low, medium and high load factors assumptions for each technology reported in the sections 4 to 19, and which are used for the LCOE analysis for 2016 project start, and 2020-2030 commissioning

Please note that the 2016 LCOE estimate represents a project starting in 2016. The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results.

For three technologies, solar PV, offshore wind and onshore wind, Arup has assumed that load factors will increase as a result of technical improvement. The load factors for these technologies over the 2015-2020 periods are shown in tables 36 to 41 below.

Table B1 Load Factor 2015 – 2030 (Offshore All) %

%	2016	2020	2025	2030
Low	42.0%	42.0%	42.0%	42.0%
Medium	47.6%	47.6%	47.6%	47.6%
High	52.1%	52.1%	52.1%	52.1%

Table B2 Load Factor 2015 – 2030 (Offshore Round 2) %

%	2016	2020	2025	2030
Low	42.1%	42.1%	42.1%	42.1%
Medium	45.5%	45.5%	45.5%	45.5%
High	50.5%	50.5%	50.5%	50.5%

Table B3 Load Factor 2015 – 2030 (Offshore Round 3)* %

%	2016	2020	2025	2030
Low	42.1%	42.1%	42.1%	42.1%
Medium	49.8%	49.8%	49.8%	49.8%
High	54.6%	54.6%	54.6%	54.6%

**Round 3 project assumes project commissioning from 2020.Table B2 represent the load factor expected to be achieved at 2020 and assumed constant thereafter.*

Table B4 Load Factor 2015 – 2030 (Offshore >30km) %

%	2016	2020	2025	2030
Low	42.1%	42.1%	42.1%	42.1%
Medium	49.7%	49.7%	49.7%	49.7%
High	54.6%	54.6%	54.6%	54.6%

Table B5 Load Factor 2015 – 2030 (Offshore <30km) %

%	2016	2020	2025	2030
Low	42.0%	42.0%	42.0%	42.0%
Medium	45.4%	45.4%	45.4%	45.4%
High	50.5%	50.5%	50.5%	50.5%

Table B6 Load Factor 2015 – 2030 (Offshore <30m sea depth) %

%	2016	2020	2025	2030
Low	42.1%	42.1%	42.1%	42.1%
Medium	45.6%	45.6%	45.6%	45.6%
High	50.6%	50.6%	50.6%	50.6%

Table B7 Load Factor 2015 – 2030 (Offshore >30m sea depth) %

%	2016	2020	2025	2030
Low	42.1%	42.1%	42.1%	42.1%
Medium	49.9%	49.9%	49.9%	49.9%
High	54.6%	54.6%	54.6%	54.6%

Table B8 Load Factor 2015 – 2030 (Onshore wind >5MW, UK) %

%	2016	2020	2025	2030
Low	28.3%	28.3%	28.3%	28.3%
Medium	32.6%	32.6%	32.6%	32.6%
High	41.6%	41.6%	41.6%	41.6%

Table B9 Load Factor 2015 – 2030 (Onshore wind, England) %

%	2016	2020	2025	2030
Low	29.6%	29.6%	29.6%	29.6%
Medium	32.5%	32.5%	32.5%	32.5%
High	37.6%	37.6%	37.6%	37.6%

Table B10 Load Factor 2015 – 2030 (Onshore wind, Scotland) %

%	2016	2020	2025	2030
Low	30.1%	30.1%	30.1%	30.1%
Medium	33.8%	33.8%	33.8%	33.8%
High	41.6%	41.6%	41.6%	41.6%

Table B11 Load Factor 2015 – 2030 (Onshore wind, Wales) %

%	2016	2020	2025	2030
Low	28.1%	28.1%	28.1%	28.1%
Medium	29.3%	29.3%	29.3%	29.3%
High	31.5%	31.5%	31.5%	31.5%

Table B12 Load Factor 2015 – 2030 (Onshore wind, Northern Ireland) %

%	2016	2020	2025	2030
Low	30.6%	30.6%	30.6%	30.6%
Medium	33.2%	33.2%	33.2%	33.2%
High	36.1%	36.1%	36.1%	36.1%

Table B13 Load Factor 2015 – 2030 (PV >5MW)* %

%	2016	2020	2025	2030
Low	10.1%	10.1%	10.1%	10.1%
Medium	11.1%	11.1%	11.1%	11.1%
High	11.8%	14.6%	14.6%	14.6%

**The high load factor is based on an optimistic scenario which assumes that more efficient technologies become as cheap as current technologies by the year 2020.*

Table B14 Load Factor 2015 – 2030 (PV 1 to 5MW, ground)* %

%	2016	2020	2025	2030
Low	10.1%	10.1%	10.1%	10.1%
Medium	11.1%	11.1%	11.1%	11.1%
High	11.8%	14.6%	14.6%	14.6%

**The high load factor is based on an optimistic scenario which assumes that more efficient technologies become as cheap as current technologies by the year 2020.*

Table B15 Load Factor 2015 – 2030 (PV 1 to 5MW, building mounted)* %

%	2016	2020	2025	2030
Low	10.1%	10.1%	10.1%	10.1%
Medium	11.1%	11.1%	11.1%	11.1%
High	11.8%	14.6%	14.6%	14.6%

**The high load factor is based on an optimistic scenario which assumes that more efficient technologies become as cheap as current technologies by the year 2020.*

Table B16 Load Factor 2015 – 2030 (Biomass CHP condensing*) %

%	2016	2020	2025	2030
Low	72.8%	72.8%	72.8%	72.8%
Medium	80.3%	80.3%	80.3%	80.3%
High	89.2%	89.2%	89.2%	89.2%

** Assumed 17MWe*

Table B17 Load Factor 2015 – 2030 (Biomass CHP CHP-mode) %

%	2016	2020	2025	2030
Low	72.8%	72.8%	72.8%	72.8%
Medium	80.3%	80.3%	80.3%	80.3%
High	89.2%	89.2%	89.2%	89.2%

** Assumed 17MWe*

Table B18 Load Factor 2015 – 2030 (ACT Standard) %

%	2016	2020	2025	2030
Low	79.3%	79.3%	79.3%	79.3%
Medium	83.2%	83.2%	83.2%	83.2%
High	91.3%	91.3%	91.3%	91.3%

Table B19 Load Factor 2015 – 2030 (ACT Advanced) %

%	2016	2020	2025	2030
Low	79.3%	79.3%	79.3%	79.3%
Medium	83.2%	83.2%	83.2%	83.2%
High	91.3%	91.3%	91.3%	91.3%

Table B20 Load Factor 2015 – 2030 (ACT CHP) %

%	2016	2020	2025	2030
Low	79.3%	79.3%	79.3%	79.3%
Medium	83.2%	83.2%	83.2%	83.2%
High	91.3%	91.3%	91.3%	91.3%

Table B21 Load Factor 2015 – 2030 (Anaerobic Digestion) %

%	2016	2020	2025	2030
Low	52.8%	52.8%	52.8%	52.8%
Medium	79.1%	79.1%	79.1%	79.1%
High	94.1%	94.1%	94.1%	94.1%

Table B22 Load Factor 2015 – 2030 (Anaerobic Digestion CHP) %

%	2016	2020	2025	2030
Low	52.8%	52.8%	52.8%	52.8%
Medium	79.1%	79.1%	79.1%	79.1%
High	94.1%	94.1%	94.1%	94.1%

Table B23 Load Factor 2015 – 2030 (Dedicated Biomass) %

%	2016	2020	2025	2030
Low	85.0%	85.0%	85.0%	85.0%
Medium	89.3%	89.3%	89.3%	89.3%
High	95.8%	95.8%	95.8%	95.8%

Table B24 Load Factor 2015 – 2030 (Biomass Conversion) %

%	2016	2020	2025	2030
Low	72.0%	72.0%	72.0%	72.0%
Medium	79.4%	79.4%	79.4%	79.4%
High	86.7%	86.7%	86.7%	86.7%

Table B25 Load Factor 2015 – 2030 (Energy from Waste) %

%	2016	2020	2025	2030
Low	80.6%	80.6%	80.6%	80.6%
Medium	87.6%	87.6%	87.6%	87.6%
High	94.8%	94.8%	94.8%	94.8%

Table B26 Load Factor 2015 – 2030 (Energy from Waste CHP, Condensing) %

%	2016	2020	2025	2030
Low	80.6%	80.6%	80.6%	80.6%
Medium	87.6%	87.6%	87.6%	87.6%
High	94.8%	94.8%	94.8%	94.8%

Table B27 Load Factor 2015 – 2030 (Energy from Waste CHP, CHP-mode) %

%	2016	2020	2025	2030
Low	80.6%	80.6%	80.6%	80.6%
Medium	87.6%	87.6%	87.6%	87.6%
High	94.8%	94.8%	94.8%	94.8%

Table B28 Load Factor 2015 – 2030 (Landfill Gas) %

%	2016	2020	2025	2030
Low	20.9%	20.9%	20.9%	20.9%
Medium	58.1%	58.1%	58.1%	58.1%
High	84.1%	84.1%	84.1%	84.1%

Table B29 Load Factor 2015 – 2030 (Sewage Gas) %

%	2016	2020	2025	2030
Low	48.5%	48.5%	48.5%	48.5%
Medium	51.3%	51.3%	51.3%	51.3%
High	55.2%	55.2%	55.2%	55.2%

Table B30 Load Factor 2015 – 2030 (Wave Energy) %

%	2016	2020	2025	2030
Low	33.3%	33.3%	33.3%	33.3%
Medium	36.8%	36.8%	36.8%	36.8%
High	41.1%	41.1%	41.1%	41.1%

Table B31 Load Factor 2015 – 2030 (Tidal Stream) %

%	2016	2020	2025	2030
Low	29.2%	29.2%	29.2%	29.2%
Medium	32.9%	32.9%	32.9%	32.9%
High	38.2%	38.2%	38.2%	38.2%

Table B32 Load Factor 2015 – 2030 (Geothermal CHP) %

%	2016	2020	2025	2030
Low	90.0%	90.0%	90.0%	90.0%
Medium	90.4%	90.4%	90.4%	90.4%
High	91.2%	91.2%	91.2%	91.2%

Table B33 Load Factor 2015 – 2030 (Co-firing Enhanced) %

%	2016	2020	2025	2030
Low	72.5%	72.5%	72.5%	72.5%
Medium	72.5%	72.5%	72.5%	72.5%
High	72.5%	72.5%	72.5%	72.5%

Table B34 Load Factor 2015 – 2030 (Hydro Large Store) %

%	2016	2020	2025	2030
Medium	45.3%	45.3%	45.3%	45.3%

Table B35 Load Factor 2015 – 2030 (Hydro 5-16MW) %

%	2016	2020	2025	2030
Low	33.9%	33.9%	33.9%	33.9%
Medium	35.7%	35.7%	35.7%	35.7%
High	55.1%	55.1%	55.1%	55.1%

Table B36 Medium Gross Load Factor in Commissioning Year 2016 – 2025 (All Technologies) %

Renewable technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore wind	30.9%	31.3%	31.6%	32.0%	32.3%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
Offshore wind R3	43.5%	44.8%	46.0%	47.3%	48.6%	49.8%	49.8%	49.8%	49.8%	49.8%	49.8%
Solar (all scales and types)	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%
ACT (all types)	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%
Biomass CHP	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%
Biomass Conversion	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%
Energy from Waste (CHP)	87.6%	87.6%	87.6%	87.6%	87.6%	87.6%	87.6%	87.6%	87.6%	87.6%	87.6%
Dedicated Biomass	89.3%	89.3%	89.3%	89.3%	89.3%	89.3%	89.3%	89.3%	89.3%	89.3%	89.3%
Anaerobic Digestion (CHP)	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%
Landfill Gas	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%
Sewage Gas	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%
Tidal Stream	32.9%	32.9%	32.9%	32.9%	32.9%	32.9%	32.9%	32.9%	32.9%	32.9%	32.9%
Wave	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%
Geothermal (CHP)	90.4%	90.4%	90.4%	90.4%	90.4%	90.4%	90.4%	90.4%	90.4%	90.4%	90.4%
Biomass Co-firing	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%
Hydro (large store)	45.3%	45.3%	45.3%	45.3%	45.3%	45.3%	45.3%	45.3%	45.3%	45.3%	45.3%
Hydro (5-16MW)	35.7%	35.7%	35.7%	35.7%	35.7%	35.7%	35.7%	35.7%	35.7%	35.7%	35.7%

Table B37 Low Gross Load Factor in Commissioning Year 2016 – 2025 (All Technologies) %

Renewable technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore wind	26.2%	26.7%	27.1%	27.5%	27.9%	28.3%	28.3%	28.3%	28.3%	28.3%	28.3%
Offshore wind R3	41.1%	41.1%	41.1%	41.1%	41.1%	42.1%	42.1%	42.1%	42.1%	42.1%	42.1%
Solar (all scales and types)	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%
ACT (all types)	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%
Biomass CHP	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%
Biomass Conversion	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%
Energy from Waste (CHP)	80.6%	80.6%	80.6%	80.6%	80.6%	80.6%	80.6%	80.6%	80.6%	80.6%	80.6%
Dedicated Biomass	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
Anaerobic Digestion (CHP)	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%
Landfill Gas	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%
Sewage Gas	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%
Tidal Stream	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%
Wave	33.3%	33.3%	33.3%	33.3%	33.3%	33.3%	33.3%	33.3%	33.3%	33.3%	33.3%
Geothermal (CHP)	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Biomass Co-firing	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%
Hydro (5-16MW)	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%

Table B38 High Gross Load Factor in Commissioning Year 2016 – 2025 (All Technologies) %

Renewable technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore wind	38.6%	39.2%	39.8%	40.4%	41.0%	41.6%	41.6%	41.6%	41.6%	41.6%	41.6%
Offshore wind R3	42.9%	44.1%	45.4%	46.6%	47.9%	54.6%	54.6%	54.6%	54.6%	54.6%	54.6%
Solar (all scales and types)	11.1%	11.8%	12.5%	13.2%	13.9%	14.6%	14.6%	14.6%	14.6%	14.6%	14.6%
ACT (all types)	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%
Biomass CHP	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%
Biomass Conversion	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%
Energy from Waste (CHP)	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%
Dedicated Biomass	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%
Anaerobic Digestion (CHP)	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%
Landfill Gas	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%
Sewage Gas	55.2%	55.2%	55.2%	55.2%	55.2%	55.2%	55.2%	55.2%	55.2%	55.2%	55.2%
Tidal Stream	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%
Wave	41.1%	41.1%	41.1%	41.1%	41.1%	41.1%	41.1%	41.1%	41.1%	41.1%	41.1%
Geothermal (CHP)	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%
Biomass Co-firing	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%
Hydro (5-16MW)	55.1%	55.1%	55.1%	55.1%	55.1%	55.1%	55.1%	55.1%	55.1%	55.1%	55.1%

Table B39 Medium Net Load Factor in Commissioning Year 2016 – 2025 (All Technologies) %

Renewable technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore wind	30.0%	30.3%	30.7%	31.0%	31.3%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Offshore wind R3	41.6%	42.8%	44.0%	45.2%	46.5%	47.7%	47.7%	47.7%	47.7%	47.7%	47.7%
Solar (all scales and types)	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
ACT (all types)	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%
Biomass CHP	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%	80.3%
Biomass Conversion	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%	79.4%
Energy from Waste (CHP)	81.5%	81.5%	81.5%	81.5%	81.5%	81.5%	81.5%	81.5%	81.5%	81.5%	81.5%
Dedicated Biomass	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%
Anaerobic Digestion (CHP)	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%	79.1%
Landfill Gas	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%	58.1%
Sewage Gas	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%
Tidal Stream	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%
Wave	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
Geothermal (CHP)	81.7%	81.7%	81.7%	81.7%	81.7%	81.7%	81.7%	81.7%	81.7%	81.7%	81.7%
Biomass Co-firing	54.4%	54.4%	54.4%	54.4%	54.4%	54.4%	54.4%	54.4%	54.4%	54.4%	54.4%
Hydro (large store)	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%
Hydro (5-16MW)	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%

Table B40 Low Net Load Factor in Commissioning Year 2016 – 2025 (All Technologies) %

Renewable technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore wind	25.0%	25.4%	25.8%	26.2%	26.6%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
Offshore wind R3	39.0%	39.0%	39.0%	39.0%	39.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Solar (all scales and types)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
ACT (all types)	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%	79.3%
Biomass CHP	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%	72.8%
Biomass Conversion	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%	72.0%
Energy from Waste (CHP)	70.7%	70.7%	70.7%	70.7%	70.7%	70.7%	70.7%	70.7%	70.7%	70.7%	70.7%
Dedicated Biomass	73.8%	73.8%	73.8%	73.8%	73.8%	73.8%	73.8%	73.8%	73.8%	73.8%	73.8%
Anaerobic Digestion (CHP)	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%	52.8%
Landfill Gas	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%	20.9%
Sewage Gas	41.2%	41.2%	41.2%	41.2%	41.2%	41.2%	41.2%	41.2%	41.2%	41.2%	41.2%
Tidal Stream	26.9%	26.9%	26.9%	26.9%	26.9%	26.9%	26.9%	26.9%	26.9%	26.9%	26.9%
Wave	24.3%	24.3%	24.3%	24.3%	24.3%	24.3%	24.3%	24.3%	24.3%	24.3%	24.3%
Geothermal (CHP)	81.0%	81.0%	81.0%	81.0%	81.0%	81.0%	81.0%	81.0%	81.0%	81.0%	81.0%
Biomass Co-firing	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%
Hydro (large store)	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%
Hydro (5-16MW)	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%

Table B41 High Net Load Factor in Commissioning Year 2016 – 2025 (All Technologies) %

Renewable technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore wind	38.0%	38.6%	39.2%	39.8%	40.4%	41.0%	41.0%	41.0%	41.0%	41.0%	41.0%
Offshore wind R3	41.6%	42.8%	44.0%	45.2%	46.5%	53.0%	53.0%	53.0%	53.0%	53.0%	53.0%
Solar (all scales and types)	11.0%	11.7%	12.4%	13.1%	13.8%	14.5%	14.5%	14.5%	14.5%	14.5%	14.5%
ACT (all types)	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%	91.3%
Biomass CHP	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%	89.2%
Biomass Conversion	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%
Energy from Waste (CHP)	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%	94.8%
Dedicated Biomass	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%
Anaerobic Digestion (CHP)	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%
Landfill Gas	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%	84.1%
Sewage Gas	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%
Tidal Stream	36.3%	36.3%	36.3%	36.3%	36.3%	36.3%	36.3%	36.3%	36.3%	36.3%	36.3%
Wave	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
Geothermal (CHP)	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%
Biomass Co-firing	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%	63.8%
Hydro (large store)	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%	44.5%
Hydro (5-16MW)	54.3%	54.3%	54.3%	54.3%	54.3%	54.3%	54.3%	54.3%	54.3%	54.3%	54.3%

Appendix C

Cost Indexes

C1 Cost Indexes

For the cost analysis Arup has applied the following cost reduction profiles. The following tables present the cost reduction profiles that Arup has applied to construction cost and operating cost. A view on the future direction of cost has been arrived at based on published data, views captured via the stakeholder engagement process and internal technical knowledge. The methodology for constructing these cost reduction profiles is provided in **Appendix E**

In these tables the cost indices are applied to the capital costs at the Final Investment Decision time of the project lifecycle.

Please note that the 2016 LCOE estimate represents a project starting in 2016. The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 LCOE values are therefore not directly comparable with the figures presented below.

Table C1 Change in Capital Cost 2015 – 2030 (All Technologies) %

Renewable technology	2016	2020	2025	2030
Onshore wind (UK, England, Scotland, Wales, NI)	100.0%	95.0%	91.7%	89.5%
Offshore wind (R2, R3, >30km, <30km, <30m, >30m)	100.0%	92.3%	85.5%	81.2%
Solar (>5MW, 1-5MW ground, 1-5MW building)	100.0%	78.5%	72.9%	69.0%
ACT (Standard, Advanced, CHP)	100.0%	94.2%	89.4%	84.9%
Biomass CHP*	100.0%	110.0%	111.5%	110.4%
Biomass Conversion	100.0%	100.0%	100.0%	100.0%
Energy from Waste (CHP)	100.0%	98.5%	97.3%	96.3%
Dedicated Biomass	100.0%	98.4%	97.1%	96.1%
Anaerobic Digestion (CHP)	100.0%	100.0%	100.0%	100.0%
Landfill Gas	100.0%	100.0%	100.0%	100.0%
Sewage Gas	100.0%	100.0%	100.0%	100.0%
Tidal Stream	100.0%	90.3%	75.1%	58.8%
Wave	100.0%	79.4%	62.0%	46.8%
Geothermal (CHP)	100.0%	98.0%	95.4%	93.3%
Biomass Co-firing (Enhanced)	100.0%	100.0%	100.0%	100.0%
Hydro (5-16MW, Large Store)	100.0%	100.0%	100.0%	100.0%

** Assumed 17MWe*

Table C2 Change in Operating Cost 2015 – 2030 (All Technologies) %

Renewable technology	2016	2020	2025	2030
Onshore wind (UK, England, Scotland, Wales, NI)	100%	98%	95%	95%
Offshore wind (R3, >30km, >30m)	100%	94%	93%	94%
Offshore wind (R2, <30km, <30m)	100%	94%	90%	88%
Solar (>5MW, 1-5MW ground, 1-5MW building)	100%	83%	78%	74%
ACT (Standard, Advanced, CHP)	100%	97%	94%	92%
Biomass CHP*	100%	108%	109%	109%
Biomass Conversion	100%	100%	100%	100%
Energy from Waste (CHP)	100%	97%	96%	94%
Dedicated Biomass	100%	100%	100%	100%
Anaerobic Digestion (CHP)	100%	100%	100%	100%
Landfill Gas	100%	100%	100%	100%
Sewage Gas	100%	100%	100%	100%
Tidal Stream	100%	83%	67%	50%
Wave	100%	81%	61%	42%
Geothermal (CHP)	100%	100%	100%	100%
Biomass Co-firing (Enhanced)	100%	100%	100%	100%
Hydro (5-16MW, Large Store)	100%	100%	100%	100%

** Assumed 17MWe*

Appendix D

Pre-development, construction and operational time periods

D1 Pre-development, construction and operational time periods

The following provides a summary of the high, medium and low time period assumptions used for LCOE modelling.

Table D1: Conversion (years)

Period	Low	Medium	High
Pre-development	2.0	2.0	2.0
Construction	2.0	2.3	2.5
Operating	15.0	15.0	15.0

Table D2: Co-firing (years)

Period	Low	Medium	High
Pre-development	1.5	1.5	1.5
Construction	1.0	1.0	1.0
Operating	22.0	22.0	22.0

Table D3: Dedicated Biomass (years)

Period	Low	Medium	High
Pre-development	2.0	3.0	4.0
Construction	2.2	2.2	2.2
Operating	25.0	25.0	25.0

Table D4: EfW (years)

Period	Low	Medium	High
Pre-development	2.3	4.4	6.4
Construction	2.7	3.0	3.4
Operating	30.0	35.0	40.0

Table D5: EfW CHP (years)

Period	Low	Medium	High
Pre-development	2.3	4.4	6.4
Construction	2.7	3.0	3.4
Operating	30.0	35.0	40.0

Table D6: Anaerobic Digestion (years)

Period	Low	Medium	High
Pre-development	1.5	1.5	1.5
Construction	0.6	0.8	1.0
Operating	20.0	20.0	20.0

Table D7: Anaerobic Digestion CHP (years)

Period	Low	Medium	High
Pre-development	1.5	1.5	1.5
Construction	0.6	0.8	1.0
Operating	20.0	20.0	20.0

Table D8: Wave (years)

Period	Low	Medium	High
Pre-development	3.0	3.0	3.0
Construction	2.0	2.0	2.0
Operating	20.0	20.0	20.0

Table D9: Tidal Stream (years)

Period	Low	Medium	High
Pre-development	3.3	4.3	5.0
Construction	1.3	1.8	2.0
Operating	20.0	22.0	25.0

Table D10: Hydro Large Store (years)

Period	Low	Medium	High
Pre-development	0.0	0.0	0.0
Construction	0.0	2.0	0.0
Operating	0.0	41.0	0.0

Table D11: Hydro 5-16MW (years)

Period	Low	Medium	High
Pre-development	1.5	2.1	3.2
Construction	0.7	2.0	2.0
Operating	20.0	41.0	57.0

Table D12: Geothermal CHP (years)

Period	Low	Medium	High
Pre-development	1.0	1.0	1.0
Construction	2.0	3.0	4.0
Operating	20.0	25.0	30.0

Table D13: Landfill Gas (years)

Period	Low	Medium	High
Pre-development	0.5	0.8	1.0
Construction	0.2	0.3	0.5
Operating	28.0	27.9	28.0

Table D14: Sewage Gas (years)

Period	Low	Medium	High
Pre-development	0.5	0.5	0.5
Construction	1.5	1.8	2.0
Operating	20.0	20.0	20.0

Table D15: ACT CHP (years)

Period	Low	Medium	High
Pre-development	1.0	2.8	5.0
Construction	1.8	2.3	2.8
Operating	25.0	25.0	25.0

Table D16: Biomass CHP (years)

Period	Low	Medium	High
Pre-development	2.0	3.0	4.0
Construction	1.9	2.1	2.4
Operating	22.0	24.0	25.0

Table D17: Onshore Wind (years)

Period	Low	Medium	High
Pre-development	3.0	4.0	6.0
Construction	1.0	2.0	2.5
Operating	20.0	24.0	25.0

Table D18: Onshore Wind, England (years)

Period	Low	Medium	High
Pre-development	3.0	4.0	6.0
Construction	1.0	2.0	2.5
Operating	20.0	24.0	25.0

Table D19: Onshore Wind, Scotland (years)

Period	Low	Medium	High
Pre-development	3.0	4.0	6.0
Construction	1.0	2.0	2.5
Operating	20.0	24.0	25.0

Table D20: Onshore Wind, Wales (years)

Period	Low	Medium	High
Pre-development	3.0	4.0	6.0
Construction	1.0	2.0	2.5
Operating	20.0	24.0	25.0

Table D21: Onshore Wind, Northern Ireland (years)

Period	Low	Medium	High
Pre-development	3.0	4.0	6.0
Construction	1.0	2.0	2.5
Operating	20.0	24.0	25.0

Table D22: Offshore (years)

Period	Low	Medium	High
Pre-development	3.3	4.5	6.0
Construction	1.8	3.0	4.5
Operating	20.0	23.0	25.0

Table D23: Offshore Round Two (years)

Period	Low	Medium	High
Pre-development	3.3	4.5	6.0
Construction	1.8	3.0	4.5
Operating	20.0	23.0	25.0

Table D24: Offshore Round Three (years)

Period	Low	Medium	High
Pre-development	3.3	4.5	6.0
Construction	1.8	3.0	4.5
Operating	18.8	22.0	24.2

Table D25: Offshore >30km (years)

Period	Low	Medium	High
Pre-development	3.3	4.5	6.0
Construction	1.8	3.0	4.5
Operating	20.0	23.0	25.0

Table D26: Offshore <30km (years)

Period	Low	Medium	High
Pre-development	3.3	4.5	6.0
Construction	1.8	3.0	4.5
Operating	20.0	23.0	25.0

Table D27: Offshore <30m (years)

Period	Low	Medium	High
Pre-development	3.3	4.5	6.0
Construction	1.8	3.0	4.5
Operating	20.0	23.0	25.0

Table D28: Offshore >30m (years)

Period	Low	Medium	High
Pre-development	3.3	4.5	6.0
Construction	1.8	3.0	4.5
Operating	20.0	23.0	25.0

Table D29: ACT Standard (years)

Period	Low	Medium	High
Pre-development	1.0	2.8	6.5
Construction	2.0	2.0	2.3
Operating	25.0	25.0	25.0

Table D30: ACT Advanced (years)

Period	Low	Medium	High
Pre-development	1.0	2.8	5.0
Construction	1.8	2.3	2.8
Operating	25.0	25.0	25.0

Table D31: PV >5MW (years)

Period	Low	Medium	High
Pre-development	0.5	0.8	1.3
Construction	0.2	0.3	0.5
Operating	25.0	25.0	25.0

Table D32: PV 1-5MW Ground Mounted (years)

Period	Low	Medium	High
Pre-development	0.5	0.8	1.0
Construction	0.2	0.3	0.5
Operating	25.0	25.0	25.0

Table D33: PV 1-5MW Building mounted (years)

Period	Low	Medium	High
Pre-development	0.5	0.8	1.0
Construction	0.2	0.3	0.6
Operating	25.0	25.0	25.0

Appendix E

Cost Reduction Methodology

E1 Cost Reduction Forecast Methodology

Our approach to estimate cost reduction and project capex, opex and levelised costs in 2020 and 2030 is based on a combination of two processes:

- Literature review on learning rates and cost reduction.
- Information gathered through stakeholders interviews.

Using both sets of information we develop a model that determines a future adjustment index for both capex and opex that can be used to estimate future levelised costs. Table E1 below provides a summary of the learning rates assumed by and change in cost index per technology over the period 2015 to 2030.

Literature review

1. Development of a top-down calibration of international well-respected learning rates forecasts (e.g. from the IEA in the World Energy Outlook; near-term by IRENA, by Bloomberg or by relevant international trade organisations for the respective technologies)
2. The review of respected global forecasts of capacity expansions such as from the IEA in the World Energy Outlook which can form the basis for assessing own trend data for key technology components e.g. modules and inverters for the PV market.
3. Review of the existing research material on historical cost trends. We have used data such as the solar pricing indices (module / inverter price indices), the National Renewable Energy Laboratory, the US Department of Energy, IRENA, Bloomberg data, and many others.

Cost Forecast Model

4. Capex and opex costs was broken down into separate components. The key driver of costs for each component was determined.
5. The research in steps one to three was used to determine how each driver may change in the future and create a Component Cost Index, and apply the Index as an adjustment factor to the components costs in the future (to 2030)
   a) Where learning rates for some components are linked to deployment rates (for example turbine costs) – we may use our research into global or EU-wide deployment rates or our estimates for UK deployment rates.
   b) Where costs are linked to geographical location (for example grid connection for offshore wind) we make an assessment of typical location (e.g. distance from shore) for projects in the relevant years and estimate how costs may change over time.
6. After the Component Cost Index was assessed for each component it was applied to 2020 and 2030 costs for base year 2014

7. Cost was then aggregated from various components to obtain the future 2020 and 2030 capex and opex costs that are used in the levelised cost model.

Stakeholder survey

8. As part of our questionnaire Arup asked stakeholders to provide information regarding costs for capex and opex for 2020 and 2030.

9. The output from the stakeholders' responses were summarised to create 2020 and 2030 costs forecast, using a similar model as per the methodology illustrated above.

10. The final step was to integrate the results of the two processes (Literature-based and Stakeholder-based) to determine our estimate for 2020 and 2030 costs.

11. While each technology followed the steps outlined above, the final cost reduction factors were determined differently for each technology because of data availability and suitability.

E2 Cost Reduction by Technology

While each cost reduction factor was calculated based on the steps presented above, technology specific cost reduction factors were determined based on suitable and available data.

Offshore Wind Round 2 and 3

For offshore wind (Round 2 and 3) Arup relied primarily on learning rates collected via the literature review. There was limited information following return of the stakeholder survey.

Arup divided capex costs into four categories: turbine; foundation; cables (Grid connections); and offshore substation. It was assumed that turbine and foundation cost learning rates were linked to global deployment, cables and substation linked to UK deployment. Additionally, we considered other cost factors such as distance from shore and water depth for categories such as foundation, grid connection, and offshore substation cost. Opex was also divided into four categories: fixed O&M; variable O&M; insurance; and grid costs. For grid costs we assumed the OFTO transfer fee is dependent on the construction cost of transmission. For fixed O&M Arup used stakeholder data; insurance costs were linked to the change in capex cost.

Onshore Wind

For onshore wind Arup received a good response from stakeholders to support the analysis in addition to the available literature. The learning rate was split by cost component. For example, turbine costs were assumed to have a different learning rate to other onshore components (a combination of literature review and stakeholder responses) and were linked to global deployment. Foundation costs were also linked to global deployment. The remaining capex costs were linked to

UK onshore wind deployment. Arup also considered other cost factors for onshore wind such as how project size affects capex. For opex Arup utilised information provided by the stakeholders.

Solar PV

Arup received a limited stakeholder response on expected change in cost. The cost reduction calculation therefore relied upon on data collected via the literature review. For the analysis Arup used different learning rate assumptions for module and balance of system; module cost reduction was linked to global PV deployment and balance of system to UK deployment. A recent report by the STA provided additional information on the potential for cost reduction in other components. Arup assumed that the opex cost reduction was a combination of information from the STA's report and literature review. When the Arup learning rate and cost reduction factors were compared to the ranges provided in the stakeholder responses, they corresponded closely.

Biomass CHP

There was limited data available following the literature review. Arup was however able to use stakeholder responses to inform the analysis, Arup used the stakeholder survey data to inform the capex cost forecast and opex forecast.

ACT (Advanced and Standard)

There was limited data available following the literature review. Arup did have a positive response from stakeholders. Therefore, the analysis was based primarily on stakeholder survey responses to estimate capex and opex costs.

Dedicated Biomass

Due to limited data on dedicated biomass Arup divided capex into construction and grid connection costs. A learning rate factor was applied to construction cost which was linked to global deployment. It was difficult to find reliable data on expected change in opex, therefore based on an internal consultation it is Arup's view that there is limited to potential for change in opex cost. Therefore, the opex adjustment factor for dedicated biomass was assumed constant.

For biomass conversion there is a limited number of coal plants which can be converted with a 'cap' on deployment the technology. Arup has therefore kept capex and opex adjustment factors constant.

Waste related technologies

For EfW and EfW CHP Arup divided capex into three components, equipment and machinery, flue gas treatment, building and civils. Arup applied its learning rate factor to all factors except building and civils.

The capex adjustment factor Arup used was based primarily on information collected via a literature review. For opex, Arup identified four components, fixed and variable O&M, insurance and UoS. Based on information provided by the stakeholders and their views on how these costs could change in the future, Arup was able to estimate an opex adjustment factor.

For Anaerobic Digestion the literature review did not indicate any changes in costs for the future. IRENA classified AD as a mature technology. In addition there was no expectation from stakeholders for further cost reduction. For the analysis Arup therefore assumed that the capex and opex adjustment factor for AD and AD CHP is constant.

For Landfill and Sewage Gas, the literature review did not locate any reliable data in terms of future learning for these technologies. Stakeholders for sewage gas said that they had no expectations of future cost change. In addition, there are very few landfill and sewage gas projects planned for development in the UK. Arup has therefore assumed that both capex and opex adjustment factors for Landfill and Sewage Gas remain constant.

Wave and tidal technologies

Wide research has been carried out on wave and tidal technologies in the UK. Recent work by Renewable UK and ORE Catapult are good sources of information and learning. Arup divided capex into four components: the PTO system; installation; grid connection; foundation and metering. A learning rate was applied to all of the capex components, with our PTO system's learning linked to global deployment of the technology and other components linked to UK deployment. For opex Arup split it into four categories: fixed O&M; variable O&M; insurance; and UoS. To generate an opex adjustment factor Arup used the views from the stakeholder responses.

For tidal Arup split capex into two cost components, construction and grid connection. The learning factor was then applied to both components with construction cost linked to global deployment and grid connection to UK deployment. For the opex adjustment factor, Arup used the view provided via the stakeholder engagement.

Geothermal technology

For geothermal technology learning factors were identified through the literature review. Capex has three cost components that include well drilling, equipment and grid connection cost. The learning factor was applied to the first two components and linked to global deployment. Grid connection costs were assumed constant.

Analysis of the available literature indicated that views on the change in capital cost were available and not operational costs. Arup has therefore no opex cost factor from the literature review, in addition, following consultation with stakeholders there is little expectation for opex costs to change significantly in the short to medium term. Therefore, Arup has assumed a constant opex adjustment factor.

Table E1: Cost Reduction Forecast Key Assumptions

Renewable technology	2016	2020	2025	2030	Cost reduction	Learning rates when capacity doubles
Onshore wind (UK, England, Scotland, Wales, NI)	100.0%	95.0%	91.7%	89.5%	CAGR -1% 2016-2030 16.9 GW by 2030 Final estimate take into account data from stakeholder/IEA.	Turbine -10% Foundation -8%
Offshore wind (R2, R3, >30km, <30km, <30m, >30m)	100.0%	92.3%	85.5%	81.2%	CAGR -1.4% 2016-2030 18.7 GW by 2030 Final estimate take into account data from stakeholder/UK Literature Review/IEA.	Turbine -11% Foundation -11% Cables (grid) -11% Offshore substations -11%
Solar (>5MW, 1-5MW ground, 1-5MW building)	100.0%	78.5%	72.9%	69.0%	CAGR -2.4% 2016-2030 18.3GW by 2030 Final estimate take into account data from stakeholder/IEA/ NG FES/UK Literature Review/STA.	Panel modules -18% Balance of plant -12%
ACT (Standard, Advanced, CHP)	100.0%	94.2%	89.4%	84.9%	CAGR -1.1% 2016-2030 Final estimate take into account data from stakeholders.	Stakeholder responses only
Biomass CHP*	100.0%	110.0%	111.5%	110.4%		Grid connection +5% CHP connection costs +5% Cost of other equipment +5%

						Boiler equipment costs +5%
Biomass Conversion	100.0%	100.0%	100.0%	100.0%		N/A
Energy from Waste (CHP)	100.0%	98.5%	97.3%	96.3%	CAGR -0.2% 2016-2030 1.5GW by 2030 Final estimate take into account data from stakeholder/IEA/ UK Literature Research	Equipment and machinery 5% Flue gas treatment 5%
Dedicated Biomass	100.0%	98.4%	97.1%	96.1%	CAGR -0.3% 2016-2030 3 GW by 2030 Final estimate take into account data from IEA/UK Literature Research/NG FES	Capital expenditure -5%
Anaerobic Digestion (CHP)	100.0%	100.0%	100.0%	100.0%		N/A
Landfill Gas	100.0%	100.0%	100.0%	100.0%		N/A
Sewage Gas	100.0%	100.0%	100.0%	100.0%		N/A
Tidal Stream	100.0%	90.3%	75.1%	58.8%	CAGR -3.5% 2016-2030 380 MW by 2030 Final estimate take into account data from Renewable UK/IEA/UK Literature Research	Construction 13% Grid connection 13%

Wave	100.0%	79.4%	62.0%	46.8%	CAGR -4.9% 2016-2030 200 MW by 2030 Final estimate take into account data from Renewable UK/IEA/UK Literature Research	PTO system 13% Installation 13% Foundation & metering 13% Grid connection 13%
Geothermal (CHP)	100.0%	98.0%	95.4%	93.3%	CAGR -0.5% 2016-2030 Final estimate take into account data from IEA.	Well cost 5% Equipment cost 5%
Biomass Co-firing (Enhanced)	100.0%	100.0%	100.0%	100.0%	Please see chapter 18	N/A
Hydro (5-16MW, Large Store)	100.0%	100.0%	100.0%	100.0%	Please see chapter `18	N/A

Appendix F

UoS Costs

F1 UoS Costs

Through the stakeholder engagement process Arup collected new data on UoS charges. After an internal and external review of the data it was concluded that both TNUoS and DUoS charges were representative for the technologies under review. Tables G1 to G25 provide a detailed breakdown of variable, BSUoS and UoS costs for each technology. The following provides an overview of how UoS costs have been treated for LCOE modelling purposes.

UoS costs represent the cost to a generator of connecting to and using the transmission and distribution electricity network. The UoS cost reported in Arup's analysis includes both TNUoS and DUoS costs calculated on a £/kW basis. These cost are combined for LCOE modelling.

BSUoS cost is charged to a generator on a £/MWh basis and is an output related cost. For LCOE modelling Arup combined BSUoS with variable operating cost. For BSUoS Arup used a benchmark cost provided by LeighFisher (and used for their parallel study on non-renewable costs) which represents an average balancing cost for UK generation. Please note that for the analysis two key assumptions were made:

- For the analysis UoS and BSUoS cost were assumed to remain constant over time.
- Variable cost was assumed to change with the assumed operating cost learning rate for the technology.

Table F1 Variable, BSUoS and UoS Costs 2016 – 2030 (Offshore Round 3), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	1.6	1.6	1.5	1.6
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	50,331	50,331	50,331	50,331

Table F2 Variable, BSUoS and UoS Costs 2016 – 2030 (Onshore wind >5MW, UK), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	5.2	5.1	5.0	5.0
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	3,109	3,109	3,109	3,109

Table F3 Variable, BSUoS and UoS Costs 2016 – 2030 (PV >5MW), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	0.0	0.0	0.0	0.0
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	1,513	1,513	1,513	1,513

Table F4 Variable, BSUoS and UoS Costs 2016 – 2030 (PV 1 to 5MW, ground), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	0.0	0.0	0.0	0.0
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	1,513	1,513	1,513	1,513

Table F5 Variable, BSUoS and UoS Costs 2016 – 2030 (PV 1 to 5MW, building mounted), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	3.4	2.9	2.7	2.5
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	1,513	1,513	1,513	1,513

Table F6 Variable, BSUoS and UoS Costs 2016 – 2030 (Biomass CHP condensing*), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	7.1	7.7	7.8	7.8
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,921	12,921	12,921	12,921

Table F7 Variable, BSUoS and UoS Costs 2016 – 2030 (Biomass CHP CHP-mode), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	8.5	9.1	9.3	9.2
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	15,330	15,330	15,330	15,330

Table F8 Variable, BSUoS and UoS Costs 2016 – 2030 (ACT Standard), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	19.4	18.8	18.3	17.8
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,774	12,774	12,774	12,774

Table F9 Variable, BSUoS and UoS Costs 2016 – 2030 (ACT Advanced), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	38.2	37.1	36.1	35.1
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,774	12,774	12,774	12,774

Table F10 Variable, BSUoS and UoS Costs 2016 – 2030 (ACT CHP), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	38.2	37.1	36.1	35.1
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,774	12,774	12,774	12,774

Table F11 Variable, BSUoS and UoS Costs 2016 – 2030 (Anaerobic Digestion), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	4.1	4.1	4.1	4.1
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,921	12,921	12,921	12,921

Table F12 Variable, BSUoS and UoS Costs 2016 – 2030 (Anaerobic Digestion CHP), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	4.1	4.1	4.1	4.1
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,921	12,921	12,921	12,921

Table F13 Variable, BSUoS and UoS Costs 2016 – 2030 (Dedicated Biomass), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	5.8	5.8	5.8	5.8
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,921	12,921	12,921	12,921

Table F14 Variable, BSUoS and UoS Costs 2016 – 2030 (Biomass Conversion), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	1.3	1.3	1.3	1.3
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	10,528	10,528	10,528	10,528

Table F15 Variable, BSUoS and UoS Costs 2016 – 2030 (Energy from Waste), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	23.4	22.7	22.4	22.1
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	16,686	16,686	16,686	16,686

Table F16 Variable, BSUoS and UoS Costs 2016 – 2030 (Energy from Waste CHP, Condensing), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	41.8	40.7	40.1	39.5
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	16,686	16,686	16,686	16,686

Table F17 Variable, BSUoS and UoS Costs 2016 – 2030 (Energy from Waste CHP, CHP-mode), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	53.2	51.8	51.0	50.3
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	16,686	16,686	16,686	16,686

Table F18 Variable, BSUoS and UoS Costs 2016 – 2030 (Landfill Gas), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	9.0	9.0	9.0	9.0
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	6,481	6,481	6,481	6,481

Table F19 Variable, BSUoS and UoS Costs 2016 – 2030 (Sewage Gas), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	10.5	10.5	10.5	10.5
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,921	12,921	12,921	12,921

Table F20 Variable, BSUoS and UoS Costs 2016 – 2030 (Wave Energy), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	32.3	26.0	19.8	13.6
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	46,724	46,724	46,724	46,724

Table F21 Variable, BSUoS and UoS Costs 2016 – 2030 (Tidal Stream), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	7.4	6.2	4.9	3.7
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	82,322	82,322	82,322	82,322

Table F22 Variable, BSUoS and UoS Costs 2016 – 2030 (Geothermal CHP), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	9.7	9.7	9.7	9.7
BSUoS	£/MWh	1.9	1.9	1.9	1.9
UoS (TNUoS/DUoS)	£/MW	12,921	12,921	12,921	12,921

Table F23 Variable, BSUoS and UoS Costs 2016 – 2030 (Co-firing Enhanced), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	1.5	1.5	1.5	1.5
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	18,079	18,079	18,079	18,079

Table F24 Variable, BSUoS and UoS Costs 2016 – 2030 (Hydro Large Store), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	5.9	5.9	5.9	5.9
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	7,603	7,603	7,603	7,603

Table F25 Variable, BSUoS and UoS Costs 2016 – 2030 (Hydro 5-16MW), 2014 Real Prices

Cost	Unit	2016	2020	2025	2030
Variable O&M	£/MWh	6	6	6	6
BSUoS	£/MWh	0.0	0.0	0.0	0.0
UoS (TNUoS/DUoS)	£/MW	0	0	0	0

Appendix G

Correlation Analysis

G1 Correlation Analysis

Approach to Correlation Analysis

Part of Arup's assessment to determine high and low scenarios for LCOE has included a correlation analysis of the key costs drivers for each of the of technologies under Phase 1. The analysis focused on the following four key drivers of LCOE:

- Size (MW)
- Capex (£/kW)
- Opex (£/kW)
- Load factor (%)

The initial step was to identify cost drivers which are highly correlated based on the output from stakeholder data and then test potential alternative high and low scenarios for LCOE for those relevant cases using a combination of cost drivers as opposed to taking only capex as the key determinant. For example, it was Arup's expectation that there would be a strong correlation between offshore capex and load factor i.e. more expensive projects further from shore can be expected to achieve a higher load factor. In addition, there was expected to be a correlation between capex and opex i.e. expensive projects also require expensive maintenance.

Step 1

Results of the correlation analysis suggested that only three technologies required further LCOE analysis. The following provides a summary:

- **Offshore wind:** the analysis confirmed that expensive (typically Round 3) offshore projects are associated with higher load factors. This observation is reflected in the correlation statistic for Round 3 projects (88%), >30m projects (80%) and >30km projects (98%). In addition, there is also an 87% correlation between installed capacity and cost for >30km projects. The observation confirmed that as developers move toward deeper waters away from shore, construction cost should be expected to increase.
- **PV:** the only correlation of significance is between construction and operating cost i.e. as construction cost increases operating costs can also be expected to increase.
- **Biomass CHP:** there is a strong correlation observed between capex and load factor i.e. as capex increases there is a corresponding increase for load factor.

Step 2

Table H1 provides a summary of the sensitivity analysis carried out to generate alternative LCOE ranges.

With regard to PV, using the high (low) capex and high (low) opex values for the high (and low) scenarios has the effect of slightly widening the range of LCOE. Based on our experience of existing projects and the analysis of the data from stakeholders, the new range of cost appears to be reasonable.

For biomass CHP, using the high (low) capex and low (high) load factor values for the high (and low) scenarios has the effect of slightly narrowing the range of cost. Based on our experience of existing projects and the analysis of the data from stakeholders, the new range of cost would appear to be reasonable.

For offshore wind, using the high (low) capex and low (high) load factor values for the high (and low) scenarios has the effect of narrowing the range of cost – from £78/MWh - £126/MWh in the original analysis, to £88/MWh - £116/MWh following the sensitivity testing. When considering the entire dataset for offshore wind, the new high and low scenarios are now much closer to what, based on actual data from stakeholders' responses, a 'P20' and 'P80' values would look like. The original high and low scenarios are on the other hand closer to the actual lowest and highest cost projects in the range.

For Round 3 projects, due to the limited number of data points, the range is narrowed significantly to the point where there is almost no different between the three scenarios (in fact, counterintuitively, the low scenario has actually the highest LCOE). Therefore the analysis suggest that only for the Offshore Wind "all projects" and not Round Three there is a case for potentially modifying the original approach to estimating new high and low scenarios.

Table G1 LCOE Analysis and Sensitivities, DECC Discount Rates, 2014 Real Prices £/MWh

Technology	Date	Notes	Sensitivity Low	Low	Medium	High	Sensitivity High
PV (all)	Project start 2016	Sensitivity(1) High Capex and High Opex,	**63**	66	76	93	**100**
	Commission 2020	(2) Low Capex and Low Opex	**57**	60	69	85	**91**
Biomass CHP	Project start 2016	Sensitivity (1) High Capex and High Load Factor,	**132**	125	152	176	**164**
	Commission 2020	(2) Low Capex and Low Load Factor	**132**	125	151	175	**163**
Offshore Wind (all)	Project start 2016	Sensitivity: (1) High Capex and High Load Factor,	**84**	74	97	121	**110**
	Commission 2020	(2) Low Capex and Low Load Factor	**88**	78	102	127	**116**
Offshore Wind Round Three	Project start 2016	Sensitivity (1) High Capex and High Load Factor,	**111**	94	106	121	**110**
	Commission 2020	(2) Low Capex and Low Load Factor	**116**	98	112	127	**116**

The correlation analysis was applied only to offshore wind, onshore wind, PV and biomass CHP. **After an internal and external review of the data it was concluded that no further adjustment to the data was required and the LCOEs generated were representative**. No additional correlation analysis was required

Table G2: Correlation Analysis Results

Correlation results				
Onshore wind, all				
	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	0.224894071	1		
Opex (£/MW)	0.143203056	-0.07325218	1	
LF (%)	-0.152854073	-0.300310294	0.368058179	1
Onshore wind, England				
	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	0.527178152	1		
Opex (£/MW)	-0.129189208	0.016441084	1	
LF (%)	-0.550536355	-0.521354707	0.224713054	1
Onshore wind, Wales				
	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	0.286987972	1		
Opex (£/MW)	0.260229121	-0.555085161	1	
LF (%)	-0.058128036	-0.619170376	0.638977195	1
Onshore wind, Scotland				
	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.439289131	1		
Opex (£/MW)	0.091134372	0.02147345	1	
LF (%)	-0.169148914	-0.492570982	0.182639899	1
Onshore wind, Northern Ireland (not enough data to run MS Excel correlation)				
	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-1	1		
Opex (£/MW)	1	-1	1	
LF (%)	1	-1	1	1
Offshore wind, all				
	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	0.183631532	1		
Opex (£/MW)	0.422308869	0.037663371	1	
LF (%)	0.248602279	0.63328454	-0.087873622	1
Offshore wind, Round 2				
	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			

Capex (£/kW)	-0.400412138	1		
Opex (£/MW)	0.412975655	0.315882346	1	
LF (%)	0.394504675	0.50381917	0.431166012	1

Offshore wind, Round 3

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	0.361461866	1		
Opex (£/MW)	-0.429855381	-0.813042448	1	
LF (%)	0.055896248	0.883706828	-0.674687113	1

Offshore wind, <30m

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.439118794	1		
Opex (£/MW)	0.442802058	0.349843907	1	
LF (%)	0.414701141	0.53139253	0.424208372	1

Offshore wind, >30m

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	0.563252747	1		
Opex (£/MW)	-0.01384576	-0.461937063	1	
LF (%)	0.084214494	0.80214955	-0.593543625	1

Offshore wind <30km

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.122145814	1		
Opex (£/MW)	0.694740613	0.31071615	1	
LF (%)	-0.224847644	0.497554661	-0.041569921	1

Offshore wind >30km

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	0.868964945	1		
Opex (£/MW)	0.145826904	-0.354535979	1	
LF (%)	0.942324847	0.983535449	-0.192703852	1

PV, all

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.274121385	1		
Opex (£/MW)	-0.197325131	0.879352645	1	
LF (%)	0.027335211	-0.044568399	-0.053320997	1

PV, ground 1-5MW (not enough data to run MS Excel correlation)

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			

Capex (£/kW)	#DIV/0!	1		
Opex (£/MW)	#DIV/0!	1	1	
LF (%)	#DIV/0!	-1	-1	1

PV, building 1-5MW (not enough data to run MS Excel correlation)

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	#DIV/0!	1		
Opex (£/MW)	#DIV/0!	1	1	
LF (%)	#DIV/0!	-1	-1	1

PV >5MW

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.385156197	1		
Opex (£/MW)	-0.413833495	0.452990878	1	
LF (%)	#DIV/0!	#DIV/0!	#DIV/0!	1

Biomass CHP

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.913660073	1		
Opex (£/MW)	-0.605161352	0.257818552	1	
LF (%)	-0.84393963	0.942104727	0.250217958	1

ACT, all

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.070866654	1		
Opex (£/MW)	-0.234695107	0.810097307	1	
LF (%)	-0.727355911	0.488873657	0.271628791	1

ACT, standard

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-1	1		
Opex (£/MW)	-0.436488793	0.436488793	1	
LF (%)	-1	1	0.436488793	1

ACT, advanced

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.016117052	1		
Opex (£/MW)	-0.482597722	0.883506422	1	
LF (%)	-0.760876981	0.661074965	0.935528089	1

ACT, RDF and waste fuel

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			

Capex (£/kW)	1	1		
Opex (£/MW)	-0.937125751	-0.937125751	1	
LF (%)	1	1	-0.937125751	1

ACT, RDF

	MW('e')	*Capex (£/kW)*	*Opex (£/MW)*	*LF (%)*
MW('e')	1			
Capex (£/kW)	-0.601554689	1		
Opex (£/MW)	-0.730635939	0.984933547	1	
LF (%)	-0.568424481	0.999165498	0.977048174	1

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Appendix H

Report Literature

H1 Report Literature

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Appendix I

LCOE Results Summary

I1 LCOE Results Summary

Presented on tables I1 to I35 are the levelised cost results calculated using DECC's current pre-existing hurdle rates, Arup's cost and technical parameters Tables I36 to I71 are the levelised cost results calculated using DECC's new hurdle rates, Arup's cost and technical parameters.

Please note that the 2016 LCOE estimate represents a project starting in 2016.The estimates for 2020, 2025 and 2030 represent projects commissioning in each of those years. The 2016 value is therefore not directly comparable with the commissioning year results.

LCOE Result using Arup Data and DECC Hurdle Rates

Table I1 LCOE 2016 – 2030 (Offshore All), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	75	78	74	70
Medium	98	103	97	92
High	121	127	120	114

Table I2 LCOE 2016 – 2030 (Offshore Round 2), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	73	74	72	68
Medium	91	92	90	85
High	123	125	121	115

Table I3 LCOE 2016 – 2030 (Offshore Round 3), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	94	99	93	90
Medium	107	112	106	102
High	121	127	120	116

Table I4 LCOE 2016 – 2030 (Offshore >30km), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	78	82	77	74
Medium	96	101	95	91
High	114	120	112	108

Table I5 LCOE 2016 – 2030 (Offshore <30km), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	80	84	79	75
Medium	103	108	102	97
High	138	144	136	130

Table I6 LCOE 2016 – 2030 (Offshore <30m sea depth), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	72	76	72	68
Medium	93	98	92	88
High	129	136	128	121

Table I7 LCOE 2016 – 2030 (Offshore >30m sea depth), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	88	93	87	84
Medium	102	107	101	97
High	118	124	117	113

Table I8 LCOE 2016 – 2030 (Onshore wind >5MW, UK), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	47	48	46	45
Medium	63	64	62	61
High	76	77	75	74

Table I9 LCOE 2016 – 2030 (Onshore wind, England), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	46	47	45	44
Medium	57	58	56	55
High	76	77	74	73

Table I10 LCOE 2016 – 2030 (Onshore wind, Scotland), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	53	54	52	51
Medium	63	64	62	60
High	69	70	68	67

Table I11 LCOE 2016 – 2030 (Onshore wind, Wales), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	57	58	56	55
Medium	65	65	64	63
High	84	85	83	81

Table I12 LCOE 2016 – 2030 (Onshore wind, Northern Ireland), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	59	60	58	57
Medium	69	70	68	66
High	86	87	85	83

Table I13 LCOE 2016 – 2030 (PV >5MW), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	60	53	49	47
Medium	68	60	57	54
High	79	71	67	65

Table I14 LCOE 2016 – 2030 (PV 1 to 5MW, ground), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	68	60	57	54
Medium	77	68	64	61
High	86	77	72	69

Table I15 LCOE 2016 – 2030 (PV 1 to 5MW, building mounted), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	69	61	57	54
Medium	75	66	62	59
High	83	74	69	66

Table I16 LCOE 2016 – 2030 (Biomass CHP condensing*), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	146	144	150	149
Medium	173	171	177	177
High	197	195	203	202

** Assumed 17MWe*

Table I17 LCOE 2016 – 2030 (Biomass CHP CHP-mode), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	140	139	141	139
Medium	172	171	174	171
High	201	199	204	201

** Assumed 17MWe*

Table I18 LCOE 2016 – 2030 (ACT Standard), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	58	59	54	50
Medium	84	86	80	74
High	99	100	94	88

Table I19 LCOE 2016 – 2030 (ACT Advanced), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	96	98	92	87
Medium	149	150	142	135
High	243	246	233	222

Table I20 LCOE 2016 – 2030 (ACT CHP), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	102	104	96	90
Medium	178	180	169	160
High	302	306	289	275

Table I21 LCOE 2016 – 2030 (Anaerobic Digestion), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	91	91	91	91
Medium	105	105	105	105
High	125	125	125	125

Table I22 LCOE 2016 – 2030 (Anaerobic Digestion CHP), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	93	91	86	85
Medium	109	107	102	101
High	131	128	124	122

Table I23 LCOE 2016 – 2030 (Dedicated Biomass), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	97	97	97	96
Medium	107	108	107	106
High	117	118	117	116

Table I24 LCOE 2016 – 2030 (Biomass conversion), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	85	85	85	85
Medium	87	87	87	87
High	89	89	89	89

Table I25 LCOE 2016 – 2030 (Energy from Waste), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	18	20	18	16
Medium	81	83	80	77
High	155	158	154	151

Table I26 LCOE 2016 – 2030 (Energy from Waste CHP, Condensing), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	111	117	110	107
Medium	140	147	139	136
High	174	182	173	169

Table I27 LCOE 2016 – 2030 (Energy from Waste CHP, CHP-mode), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	89	99	86	81
Medium	142	154	139	134
High	189	202	186	180

Table I28 LCOE 2016 – 2030 (Landfill Gas), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	40	40	40	40
Medium	60	60	60	59
High	80	80	80	79

Table I29 LCOE 2016 – 2030 (Sewage Gas), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	94	94	94	94
Medium	176	176	176	176
High	225	225	225	225

Table I30 LCOE 2016 – 2030 (Wave Energy), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low			214	166
Medium			333	262
High			444	352

Table I31 LCOE 2016 – 2030 (Tidal Stream), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low			221	178
Medium			343	279
High			468	383

Table I32 LCOE 2016 – 2030 (Geothermal CHP), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	32	32	7	-4
Medium	181	181	153	139
High	276	276	245	229

Table I33 LCOE 2016 – 2030 (Co-firing Enhanced), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	101	101	101	101
Medium	103	103	103	103
High	107	107	107	107

Table I34 LCOE 2016 – 2030 (Hydro Large Store), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Medium	71	69	69	69

Table I35 LCOE 2016 – 2030 (Hydro 5-16MW), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	54	54	54	54
Medium	84	84	84	84
High	92	92	92	92

LCOE Result using Arup Data and new Hurdle Rates

Table I36 LCOE 2016 – 2030 (Offshore All), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	72	76	71	68
Medium	94	99	93	89
High	116	122	115	109

Table I37 LCOE 2016 – 2030 (Offshore Round 2), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	70	74	69	66
Medium	87	92	86	82
High	117	124	116	110

Table I38 LCOE 2016 – 2030 (Offshore Round 3), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	89	93	88	85
Medium	101	106	100	96
High	114	119	113	109

Table I39 LCOE 2016 – 2030 (Offshore >30km), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	74	77	73	70
Medium	90	95	89	85
High	106	112	105	101

Table I40 LCOE 2016 – 2030 (Offshore <30km), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	77	81	76	73
Medium	99	104	98	93
High	132	138	130	124

Table I41 LCOE 2016 – 2030 (Offshore <30m sea depth), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	70	73	69	65
Medium	90	84	88	84
High	124	130	122	116

Table I42 LCOE 2016 – 2030 (Offshore >30m sea depth), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	83	87	83	80
Medium	96	100	95	91
High	111	116	110	106

Table I43 LCOE 2016 – 2030 (Onshore wind >5MW, UK), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	46	47	46	45
Medium	62	63	61	60
High	75	76	74	72

Table I44 LCOE 2016 – 2030 (Onshore wind, England), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	45	46	45	44
Medium	56	57	55	54
High	75	76	73	72

Table I45 LCOE 2016 – 2030 (Onshore wind, Scotland), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	52	53	52	51
Medium	62	63	61	60
High	69	69	67	66

Table I46 LCOE 2016 – 2030 (Onshore wind, Wales), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	57	57	56	55
Medium	64	64	63	62
High	83	84	82	80

Table I47 LCOE 2016 – 2030 (Onshore wind, Northern Ireland), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	58	59	57	56
Medium	68	69	67	66
High	85	86	84	82

Table I48 LCOE 2016 – 2030 (PV >5MW), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	65	59	55	52
Medium	74	67	63	60
High	87	80	76	73

Table I49 LCOE 2016 – 2030 (PV 1 to 5MW, ground), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	74	67	63	60
Medium	84	76	72	68
High	94	86	81	77

Table I50 LCOE 2016 – 2030 (PV 1 to 5MW, building mounted), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	75	68	63	60
Medium	81	73	69	65
High	91	82	77	73

Table I51 LCOE 2016 – 2030 (Biomass CHP condensing*), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	141	139	144	144
Medium	165	163	170	169
High	188	185	193	192

** Assumed 17MWe*

Table I52 LCOE 2016 – 2030 (Biomass CHP CHP-mode), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	134	133	135	132
Medium	163	162	165	162
High	190	188	192	189

** Assumed 17MWe*

Table I53 LCOE 2016 – 2030 (ACT Standard), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	66	67	62	57
Medium	96	98	91	85
High	113	115	107	101

Table I54 LCOE 2016 – 2030 (ACT Advanced), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	95	97	91	86
Medium	147	148	140	133
High	239	242	229	218

Table I55 LCOE 2016 – 2030 (ACT CHP), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	119	121	112	105
Medium	208	211	198	188
High	354	359	339	323

Table I56 LCOE 2016 – 2030 (Anaerobic Digestion), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	85	86	86	86
Medium	99	99	99	99
High	116	117	117	117

Table I57 LCOE 2016 – 2030 (Anaerobic Digestion CHP), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	89	88	83	82
Medium	104	103	99	97
High	125	124	120	118

Table I58 LCOE 2016 – 2030 (Dedicated Biomass), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	88	88	88	87
Medium	97	96	96	95
High	104	104	103	103

Table I60 LCOE 2016 – 2030 (Biomass conversion), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	85	85	85	85
Medium	87	87	87	87
High	88	88	88	88

Table I61 LCOE 2016 – 2030 (Energy from Waste), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	-2	-1	-3	-4
Medium	43	45	43	41
High	98	100	97	95

Table I62 LCOE 2016 – 2030 (Energy from Waste CHP, Condensing), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	96	98	84	92
Medium	121	124	120	117
High	152	155	151	148

Table I63 LCOE 2016 – 2030 (Energy from Waste CHP, CHP-mode), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	71	77	69	64
Medium	119	125	116	111
High	161	167	158	153

Table I64 LCOE 2016 – 2030 (Landfill Gas), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	43	43	43	43
Medium	67	67	67	67
High	91	91	91	91

Table I65 LCOE 2016 – 2030 (Sewage Gas), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	100	100	100	100
Medium	191	191	191	191
High	244	244	244	244

Table I66 LCOE 2016 – 2030 (Wave Energy), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	248	259	207	161
Medium	383	400	320	252
High	509	530	427	338

Table I67 LCOE 2016 – 2030 (Tidal Stream), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	237	249	213	171
Medium	364	381	328	267
High	494	516	446	365

Table I68 LCOE 2016 – 2030 (Geothermal CHP), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	34	34	9	-2
Medium	184	184	156	141
High	280	280	249	232

Table I69 LCOE 2016 – 2030 (Co-firing Enhanced), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	101	101	101	101
Medium	103	103	103	103
High	107	107	107	107

Table I70 LCOE 2016 – 2030 (Hydro Large Store), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	84	84	84	84
Medium	84	84	84	84
High	84	84	84	84

Table I71 LCOE 2016 – 2030 (Hydro 5-16MW), 2014 Real Prices £/MWh

£/MWh	2016	2020	2025	2030
Low	61	61	61	61
Medium	97	97	97	97
High	107	107	107	107

Appendix J

Peer Review

J1 Peer Review

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

From: Ajay Gambhir, Jeremy Woods and Matthew Hannon, Grantham Institute, Imperial College London

Objective: Imperial College's Grantham Institute was requested to peer review Arup's report, "Review of Renewable Electricity Generation Cost and Technical Assumptions" and provide feedback on five areas:

- Assumptions and methodology: a check of the assumptions developed with best practice and the methodology applied.
- Values stated: a view on whether the evidence from Imperial's perspective are of the 'correct' order and accurate.
- Completeness of analysis: based on experience of whether there are any gaps in the analysis and reporting.
- External perspective: whether the findings are consistent with Imperial's experience and knowledge of international approaches
- Uncertainty and ranges: provide a view on the approach for calculating values and reporting uncertainty around estimates.

Reviewer background: The Grantham Institute at Imperial College London undertakes analysis on long-term low-carbon pathways, using energy systems modelling and research into the performance and cost improvement potential of a range of low-carbon energy technologies. The Grantham Institute has been a core partner in the DECC and Defra-funded avoiding dangerous climate change research programme since 2009, with a focus on exploring the feasibility of achieving greenhouse gas emissions pathways which would avoid dangerous levels of climate change.

Other analysis by the institute, frequently in collaboration with other departments and institutes at Imperial College London, requires an understanding of the literature on future technology costs in the power generation sector.

Summary of review, Ajay Gambhir:

Methodology: For the most part the methods are clearly described. One area where greater clarity would be useful is a more detailed description of which learning rates and which deployment figures have been taken from the literature, and how these have been combined/contrasted with the stakeholder survey results to arrive at component cost reduction indices.
Arup response: Appendix E provides details of the cost reduction methodology, literature review, learning rate / cost reduction by technology and key assumptions.

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

Quantity of analysis: Several data points have been gathered, enabling a representative view of costs, with the (acknowledged) exception of solar PV.
*Arup response: comment acknowledged***.**

Values generated: The cost reduction paths of onshore wind and solar PV look reasonable in light of other literature sources, but offshore wind cost reduction projections do look on the conservative side. Some more elaboration of why this might be the case would be useful.
Arup response: conservative values for offshore wind acknowledged. Please see pg.33 for additional text on the IEA's 450 scenario

Specific comments
Literature Review: IEA World Energy Outlook is given as a source for deployment data for key renewables technologies, but it is not stated what year's outlook and which particular scenario's deployment figures are used. This is critical to driving cost reductions.
Arup response: Identified in text as the 2014 publication

Cost forecast model: Following from the above comment on the specific scenarios used to generate cost reduction factors, it should be clarified what learning rates were used and how specifically these were combined with the views of stakeholders to generate a component cost index. Currently it is not clear how much relative weight was given to stakeholders' views where they differed from the cost reductions resulting from the learning rate and deployment levels used in the literature sources.
*Arup response: please see Appendix E***.**

Correlation analysis: It would add clarity to the description and justification of the correlation analysis if some examples could be given of what correlation might be expected between specific variables, whether this is the case for the four technologies for which this analysis was performed, and therefore why further analysis was not undertaken.

Arup response: text updated under section 3.13, plus Appendix G on why additional correlation analysis was not carried out.

Onshore wind: The reductions in capital cost for onshore wind over the period 2015 to 2030 look modest though reasonable in comparison to other sources. The medium projections suggest that the cost will fall from £1,527/kW (2015) to £1,395/kW (2030), a fall of 9% over 15 years.
Arup response: PR acknowledged reasonable. No further action is required.

By comparison, the International Energy Agency's World Energy Investment Outlook (2014) – for its "450 scenario" has onshore wind in Europe falling from $1,790/kW (2012) to $1,600/kW (2035) – a fall of 11% over 23 years.

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

Offshore wind: As with onshore wind, capital cost reductions look modest. The Arup medium figures show costs falling £2,879/kW (2015) to £2,432/kW (2030), a fall of 16% over 15 years.
By comparison, the International Energy Agency's World Energy Investment Outlook (2014) – for its "450 scenario" has offshore wind in Europe falling from $5,180/kW (2012) to $3,030/kW (2035) – a fall of 42% over 23 years.
Arup response: updated text on the IEA's view included under Section 5.3.1 pg.33.

This discrepancy seems high. The International Energy Agency tends to be on the more conservative end of technology cost reduction ranges, so some explanation of differences would be beneficial, notwithstanding that the estimates are for round 3, in deeper waters with higher construction costs.
Arup response: comment acknowledged no additional adjustment required.

Solar PV: Given that the PV costs data relies more heavily on other published sources, unsurprisingly these cost reduction pathways look in line with the other literature.
Arup response: no action required

The Arup report estimates costs falling 31% over the period 2015-2030. This compares to a cost reduction of 48% over the period 2012-2035 in the IEA's World Energy Investment Outlook's "450 scenario", for both building and large-scale ground mounted PV.
Arup response: Arup forecast follows external forecast. No action required.

A recent survey of building and utility scale PV by the Grantham Institute indicates that the current cost estimates, at around £1,000/W, are reasonable for utility scale projects, although building scale projects from Arup's collected survey data seem quite low (see table below). This may be explained by the larger scale building installations that Arup's survey has included, compared to the data in the table which is a combination of household and commercial buildings.
Arup response: Arup figures look reasonable. No action is required.

Summary of review: Jeremy Woods

LCOE does not include system costs e.g. grid reinforcement etc (not from definition in Exec Summary). This should be clearly stated in the Exec summary.
Arup response: please see Section 3.10.3 for information.

Biomass fuel price is a key parameter with fuel costs typically comprising 1/3 to 2/5 of the LCOE where 'waste' and dedicated (Pellets) fuels are used. There are real risks (and uncertainty) in projections of future prices which are not properly addressed in the report.
Arup response: please see individual technology sections below

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

There are inconsistencies across all the biomass categories in terms of assumed energy contents in particular that should be resolved.
Should be clear about the uncertainty in projected costs for construction materials e.g. particularly steel, not least because of the uncertainty in the projected costs time frame of the energy prices for energy intensive material production / provision.
Arup response: Arup has not reviewed commodity prices but has assumed that these are implicitly reflected in the views of the stakeholders and literature

Occasionally the term 'negative impact on LCOE' is used and I find this 'negative impact' terminology to be confusing. I would suggest changing it to 'reduction' or 'increase' in LCOE.
Arup response: agreed. removed from the report

LCOE calculation
Hurdle rate definition required
Arup response: please see section 1.1 and 2.1 for definition and clarification.

Might mention the impact of lower fossil fuel prices on material costs and delivered costs for materials?
Arup response: Arup has not reviewed fossil fuel impacts as part of the analysis

What about exogenous impacts e.g. lower fossil fuel and material costs?
Arup response: please see above.

Use of system cost explain acronyms
Arup response: Agreed. Please see Section 3.6 for acronym.

This 'negative impact' terminology is confusing. I would suggest changing it to 'reduction' or 'increase' in LCOE.
Arup response: Agreed. removed

ACT: The technology description is confused- I would advise a major re-write
Arup response: no re-write required, DECC comments included along with Arup read through of the chapter.

Gasification is used to produce syngas
Arup response: included under Section 7.1.

Pyrolysis is used to produce bio-oil
Arup response: included under Section 7.1.

How was the assumed GCV of the fuel chosen? (Gate Fee section)

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

Arup response: please see gate fee section footnote on source of the information.

This is inconsistent with the other biomass fuel energy contents- how was the figure of 17.3 GJ/tonne chosen?
Arup response: please see gate fee section footnote on source of the information.

What source was used to provide this temperature range? Gasification usually takes place between 800 and 900 deg C.
Arup response: Agreed. Included update into the introductory section of the report (7.1)

Biomass CHP: I have concerns about the assumed energy content of the biomass fuel which is stated to be 'waste wood'. Whittaker and Murphy (2009) assume a moisture content for waste wood of 10% (wet basis). The GCV for 10% moisture wood is 16.56 GJ/tonne. They provide an average moisture content for all biomass waste of 29% which would have an energy content of c. 12.5 GJ/t. In practice, some of the material for producing the fuel could come from forest harvest residues which are c. 50% moisture when produced but are often left in the field to dry to 20% to 30% moisture. 50% moisture content material would have a GCV of less than 10 GJ/t.
Arup response: please see footnote for reference and acknowledgement of reference.

Should also include estimates of the MWth capacity.
Arup response: No action taken. All capacities are presented in MWe.

I would think obtaining planning consent is a key component of this cost and v variable between projects.
Arup response: Please see Section 8.2.1 for updated text.

Emissions abatement has been an important component in dedicated biomass CHP as far as I know- did any of the stakeholders mention this?
Arup response: please see Section 8.3.1 for updated text.

I would use the 'fuel' suffix to indicate that this value is not per unit output e.g. electricity (also need to be consistent with heat output values)
Arup response: Acknowledged. No action taken.

A GCV 12.5 GJ/tonne This seems OK to me but must be based on a relatively high moisture content for the waste wood supplies e.g. 20%+. In practice this is extremely variable with the GCV for biomass at 15% moisture = 16 GJ/tonne. I would expect the moisture content of waste wood supplies to increase as the resource undergoes greater exploitation.
Arup response: Please see footnote for reference and acknowledgement of reference.

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

I calculate this to be £33.54 per tonne waste wood. Whilst this is probably OK at the moment I think you should put in a statement that says the quantities of waste wood biomass available at this quality and price are possibly quite limited. I could point you to Whittaker & Murphy (2006) and might be able to find a more recent ref if useful?
Arup response: Acknowledged. No action taken.

LHV efficiency: Should specify these to be 27.7% c.f. DECC's 20%. This seems reasonable as the 20% was a real guestimate based on old US plant efficiencies i.e. from the late 80s and 90s.
Arup response: Acknowledged Arup figures are of the correct order.

Comparison of DECC and Arup LCOE values: This seems quite reasonable to me with the proviso that future fuel prices are likely to be quite sensitive to the anticipated overall scale of demand and it might be worth generating a cost-supply curve for biomass fuel feedstocks?
Arup response: please see footnote under Section 8.8.

Biomass Conversion: Drax's website states 'The third unit is expected to be converted in 2015/16.' - See more at: http://www.drax.com/biomass/our-biomass-plans.
Arup response: Included as footnote.

A GCV of 17GJ/tonne: This is fine, perhaps a little low. I would have used 17.5 GJ/t or 16.9 GJ/t NCV (LHV) for SE US wood pellets. I note the Lynemouth State Aid application uses 17.2 GJ/t GCV**.**
Arup response: Agreed with the Arup figures.

LHV Efficency: This seems correct- I understand DRAX's thermal efficiency is nearly 39% and Lynemouth reports 36.9% in the State Aid application.
*Arup response: Agreed with the Arup figures***.**

EfW: Need to check the GCV value used of 16.99 - I think this should be closer to 10-11 GJ/t e.g. for MSW (Cheeseman, 2014)
Arup response: Correction included into text. The GCV should have been 11 not 16.99.

Risk in the composition of the fuel should be explicitly stated
Arup response: Included as part of the footnote.

+100% LCOE seems extremely high and probably needs further justification than provided here.
Arup response: covered by with current caveats.

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

Dedicated Biomass: Should be clear that this refers to conventional dedicated biomass (have inserted in text in intro) to distinguish from ACT.
Arup response: included 'conventional' in first sentence. Section is pretty clear what the technology is. Plus having different section allows the distinction to be made.

Similar issues with the assumed use of 'waste wood' as the feedstock, including the GCV used of 12.5 GJ/t. I would think each plant will use a different mix of fuel feedstocks but mostly sawmill residues (e.g. sawdust and off-cuts) and forest residues (branches, off spec wood). This will result in a v wide range in potential energy densities for the fuel and in pre-processing infrastructure, particularly with regard to drying and comminution.

Add conventional to distinguish from ACT.
Arup response: included 'conventional' in first sentence.

A GCV of 12.5GJ/tonne: Whittaker and Murphy (2009) assume a moisture content for waste wood of 10% (wet basis). The GCV for 10% moisture wood is 16.56 GJ/tonne.
Arup response: please see Biomass CHP section where same GCV is assumed.
AD

A GCV of 16.99GJ/Tonne: Again this is too high- see comments in the EfW section. I would use a GCV of c. 10 GJ/t unless dedicated feedstocks are assumed such as maize sillage.
Arup response: info is based on WRAP data and has been referenced in the footnote.

Biomass co-firing: A GCV of 17 GJ/tonne: See comments on GCV of pellets in biomass conversion section.
Arup response: agrees with Arup's current assumption.

Marine: Reference the AMEC and Carbon Trust report on wave energy resource. Analogous report for tidal too by them I think:
https://www.carbontrust.com/media/202649/ctc816-uk-wave-energy-resource.pdf
Arup response: agreed, reference included.

Which projects were these? Also makes a difference about which technologies they were. Was it Pelamis 'Sea Snake' or Aquamarine 'Oyster' for example? Different techs represent diff costs on basis of: 1) different levels of development and 2) fundamentally different engineering challenges
Arup response: unfortunately due to confidentiality Arup can't provide details of individual projects.

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

Any details on how the internal review was performed and who performed it? Assuming this is within Arup.

Greater explanation of differences observed in DECC and ARUP modelling needed. I'm unclear why there is such a dramatic difference between some of the results e.g. OPEX costs for 2020 & 2025
Arup response: please see final paragraph of Section 15.1.

Important to explain why an increase in costs is expected from 2016 to 2020
Arup response: update included. Removal of 2016, 2020 LCOEs.

Summary of review: Matthew Hannon

Clarification required on, "reputable source of information".
Arup response: Agreed. Update included into the report.

"Published report", should be referenced.
Arup response: agreed. References included.

Do you mean 'geothermal heat-only' projects? (There are, of course, in other regions geothermal 'power-only' projects) so this is potentially ambiguous and misleading.
Arup response: agreed. Text updated to reflect the original data requested. Geothermal with and without CHP.

"For the analysis Arup engaged with Ricardo-AEA to review the efficiency of geothermal CHP", from where? Germany? If you used examples from high-enthalpy volcanic regions these might be misleading.
Arup response: agreed. Based on UK literature.

Data collection; again, the geographical provenance needs to be mentioned.
Arup response: UK focussed analysis.

"For the average ('medium') project construction cost is equal to around £6.9m/MW". What is the origin of this figure? Gold-plated govt-funded projects in Germany? This is very high compared to costs I have experienced drilling the UK's only deep geothermal boreholes in recent decades, where costs were more like £1.5M per borehole. How many boreholes is this assuming? 2 or 3? (Need to mention reinjection boreholes are necessary.
Arup response: agreed. Data is from published source of information plus internal Arup benchmarks. The £6.9/MW is an average figure across the dataset. The drilling cost of £1.5m compares well with the £1.2m Arup benchmark.

Cost and availability of onshore drilling rigs is probably THE big issue - certainly in my first-hand experience. When oil is cheap, so is drilling; when oil is dear, then geothermal is disadvantaged as it struggles to justify top rig rates.

Subject: Peer review of:

"Review of renewable electricity generation cost and technical assumptions"

Arup response: agreed. Insight included as additional text.
"This is due to increased knowledge and characteristics of the sub-surface and therefore a reduction in the risk from unproductive boreholes".

There has been a very detailed study on this by IFC, which you should read and cite:http://www.ifc.org/wps/wcm/connect/7e5eb4804fe24994b118ff23ff966f85/ifc-drilling-success-report-final.pdf?MOD=AJPERESs.
Arup response: agreed. Reference included.

These learning rates seem rather conservative: If we figured out how to reduce dry holes by 30%, for example, that would save a lot more than 2% by 2020.
Arup response: comment acknowledged, please see Executive summary.

"A comparison of the DECC assumptions and the Arup 2015 update indicates a large overall increase in construction cost of around 50%." Is this an artefact of the methodology being used? Clearly drilling costs (= construction costs in geothermal) have not done this. In fact they are probably falling.
Arup response: it is an artefact of the analysis. DECC had forecast that 2015 costs in 2011. Our comparison basically indicates that they haven't fallen as fast as expected.

"Construction costs, the 2015 estimate of £6,907/kW is significantly higher than the external cost estimate range. It should be noted that the external benchmarks are more likely to reflect international construction costs where geothermal CHP is an established", Your reasoning on which construction cost figure to use (the high one) is that the lower numbers come from places 'where geothermal is an established technology'. This begs the question: where did the previous numbers came from then?
Arup response: clarification included into text.

Summary of cost projections:

Source and geography	Current / near-term cost	2025 cost projections
Fraunhofer (2013) - Germany	Utility: $1.4/W (2013) Building: $1.7/W (2013)	Utility: $0.85/W Building: $1/W
Lazard (2014) - USA	Utility: $1.6/W (2014) Building: $3/W (2014)	n/a
IEA (2014) – Global average	Utility: $2/W (2015) Building: $4/W (2015)	Utility: $1/W Building: $1/W (for cheapest)
GTM (2014) - USA	Utility: $2.2/W (2014) / $1.2/W (2017) Building: $3/W (2014) / $2.3/W (2017)	n/a
NREL (2014) - USA	Utility: $3/W (2013)/ $1.8/W (2016) Building: $4.5/W (2013)/ $2.2/W (2016)	n/a
ITRPV (2015) - China	Utility: $1.3/W (2015) / $1.1/W (2017)	Utility: $0.8/W

In section 6.5 it is notable that by 2030, Arup's reported capex estimates are higher (in one case – 1-5MW ground-mounted PV shown in table 32 - significantly so) than DECC's current costs. Given that Arup's reported data is broadly in line with the literature, it would be useful to know why DECC's previous estimates were relatively optimistic.

References:

Fraunhofer: https://www.ise.fraunhofer.de/en/publications/studies/cost-of-electricity
GTM: http://www.greentechmedia.com/articles/read/Its-Solar-Balance-of-System-Innovation-That-Will-Drive-Cost-Reduction
ITRPV: http://www.itrpv.net/Reports/Downloads/2015/
NREL: http://www.nrel.gov/docs/fy14osti/62558.pdf
IEA: https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf
Lazard: https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf