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Anaerobic Digestion of Feedstock Grown on Marginal Land: Break-Even Electricity Prices

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Abstract: Marginal farm land is land characterised by low food, feed and fodder crop productivity due to soil and environmental limitations. Such land may however be utilised for bio-energy crop production. We investigate the economic viability of small scale combined heat and power anaerobic digestion (CHP AD) projects based on feedstock from farm waste and bio-energy crops grown on a representative temperate latitude marginal farm land in the UK. Using a realistic set of five project feedstock-mix scenarios, and considering standard technology and current market and policy regimes, we deploy a stochastic framework to assess prices of electricity required for these projects to break-even and conduct sensitivity analyses of key project parameters. Accounting for the current market prices and policy tariffs for heat, we find that critical electricity sale prices of about 17.46 p/kWh to 27.12 p/kWh are needed for the projects to break even. These prices are well above the current combined feed-in-tariff support and market prices for electricity over the past years in the UK. We conclude that the use of marginal land to generate power for export using small-scale CHP AD in the UK and the wider temperate latitude countries is unviable, if energy and farming policy regimes do not provide substantial support.

Keywords: bio-energy; anaerobic digestion; marginal land; prices; electricity; policy

1. Introduction

On-farm bio-energy generation using farm resources such as manure and feed residues can be complementary to food, feed and fodder crop production. Alternatively, arable farmland can be used directly to grow bio-energy crops as feedstock for bio-energy generation. However, resulting competition with food production and poor greenhouse gas balances are of great concern [1–5] and typically seen as lessened when bio-energy crops are rather grown on 'marginal land' [4,6], which is defined as land characterised by low food, feed and fodder crop productivity due to soil, climatic, or environmental limitations (e.g., low soil nutrient content, susceptibility to erosion, steep slope, or poor drainage) [6–8].

In light of climate change mitigation efforts, bio-energy generation on marginal land has received renewed interest [9–11]. Although there is an ongoing debate about the suitability of bio-energy crops grown on marginal land for transport and more generally [9,12–14], less work has been done on the potential of marginal land for generating electricity and/or heat, much of it taking a regional approach with specific feedstock [7,15,16]. There is also little empirical research on marginal areas outside the United States with [17] being an exception. From an economic perspective, marginality of food, feed and fodder crop production can be affected by farm subsidies and agricultural prices. Many countries of the Global North support expansion of renewable electricity and heat generation, whilst reducing support of food production. Using marginal land for electricity and heat generation, rather than food, feed and fodder crop production, might be an attractive alternative for farms in such context.

Besides biomass boilers, anaerobic digestion (AD) is currently the leading on-farm bioenergy technology in the Global North. AD generated biogas in the UK has great potential, with an estimated potential contribution of as much as 18% of the country's biogas demand of which 8.6% could come from agricultural waste and manure [18]. The literature suggests however that financial viability of AD using farming resources is highly contingent on support policy [19–22]. In the UK, three key support mechanisms, which are used in one form or another in many other countries, currently support renewable electricity generation by independent power producers: the Renewables Obligation ('RO'), the Feed-In-Tariff ('FIT') and the Contract for Difference ('CFD'). Between them, this triad of mutually exclusive mechanisms span the breadth of major renewable electricity technology types and capacity classes. A scheme similar to the FIT, called the Renewable Heat Incentive ('RHI'), supports the generation of low-carbon heat. Although there are major differences in how these support mechanisms operate, all subsidise renewable energy output over time.

The period following election of a majority conservative parliament in the UK in the spring of 2015 has seen drastic changes to energy policy, including all support mechanisms above. Although it is not easy to characterise these changes in general terms [23], it is clear that a broad shift away from technology- and capacity-specific support mechanisms (e.g., FIT, RHI, ROC) towards 'technology neutral' auction-based service contracts (e.g., 'ancillary services', 'balancing services', and the capacity market) is underway. Interestingly, the diversity of support mechanisms has hugely expanded in parallel, ushering in an unprecedented era of market regime complexity.

In May 2016, the UK Department of Energy & Climate Change (DECC) published its review of support for electricity produced from anaerobic digestion (AD). Decreases in FIT rates between 27 and 100% (Table 1) were widely foreseen following similar interventions for other technologies. Reformed support for heat from AD, meanwhile, was proposed through consultation by DECC in March 2016. The latter stated that "The Government's policy is that the primary purpose of agricultural land should be for growing food." But what about land too marginal to grow food? This is a particularly important question, when farming subsidies for such land decrease, as envisaged under the reform of the Common Agricultural Policy of the EU in the context of Brexit, for example. What conditions would need to exist for energy generation to make sense on such land?

Table 1. Changes in UK support for electricity and heat from AD 2016.

Support Mechanism	Capacity Band (kW)	Before * (p/kWh)	Current Rates ** (p/kWh)	Δ (%)
FIT	<250	8.21	5.57	−32.16
	250–500	7.58	5.27	−30.47
	500–5000	7.81	1.99	−74.52
RHI	<200	6.94	2.88	−58.50
	200–600	5.45	2.26	−58.53
	>600	2.04	0.86	−57.84

* As of 1 April 2016; ** As of July 2017.

Here, we aim to answer the above questions in terms of a single variable: the break-even price of electricity. Hence, we investigate the economic viability of small scale electricity and heat generation through AD of farm waste and bio-energy crops grown on a representative marginal farm land in Scotland's (UK) Central Belt. To calculate electricity prices at which a selection of 5 practicable project scenarios for the farm might break even, under a wide range of critical parameters, we use simulation modelling and sensitivity analyses. Our approach is novel, but builds on insights gained from past efforts of modelling farm-based AD projects. Specifically, we use a capital budgeting methodology in a stochastic framework [20,24]. This approach is robust and helps to identify project scenarios and policies that are economically most effective. Also the calculated breakeven electricity prices are gross of market prices and policy tariffs for electricity, hence implicitly affording flexibility for the reader's determination of the feasibility of projects given future changes in energy prices [25]. We focus empirically on the west of Scotland's Central Belt because the area can provide diverse crops and farm waste as feedstock, whilst the land is marginal due to soil quality, climate and limited viability of traditional farming systems [26,27]. Our findings should be transferable to a wide range of other relevant settings in the Global North.

The rest of the paper is structured as follows: in Section 2 we introduce our methods, including a detailed description of our case settings and our modelling approach. In Section 3 we introduce our data. The resulting break-even prices, their contingencies and their implications are presented and discussed in Sections 4 and 5 respectively.

2. Methods

2.1. Description of the Representative Farm in the UK Farm Context

Our analysis is based on a mixed livestock farm (Hartwood Home Farm, 3.8388° W 55.8129° N) that is representative of a large part of Scotland because of its poorly drained soils and high rainfall levels. Across Scotland, soil resource of the type found at the farm represents a high proportion (i.e., 18% [28,29]) of total land and an even higher percentage of land under grass. Lands with such disadvantaged conditions are found in other parts of the United Kingdom, especially the West, uplands and Northern Ireland, and the North-West of Europe that has a temperate climate, including poor farmland in the lower altitudes towards the coast, such as poorly draining soils in the Netherlands and western Scandinavia and wet higher altitude farmland in central Germany, eastern France and Belgium. These marginal farming areas are dominated by cattle and dairy farms, combined with limited arable farming. Wet, cool and often poorly draining soils are defining attributes of this type of marginal land that also can be found in the east of Europe, although the climate is not temperate.

Hartwood Home Farm (350 hectares) is a research farm managed by The James Hutton Institute (Scotland, UK) where the research presented in this paper is based. The farm's main strength is its ability to produce a large quantity of grass during the short growing season to support beef and sheep production. However, the growing of this grass requires high levels of support energy in the form of fertiliser applications and machinery usage. Selected cereals and roots and tubers can also be grown, but achieving harvests of acceptable quality and quantity is difficult. Typical for such areas, it has low socio-economic status, which hampers the support of farming through neighbouring consumers and industry. Like much of Scotland's Central Belt, the area is both electricity- and gas grid-constrained, with limited opportunity for exportation of electricity and/or direct injection of gas into a network.

Based on the actual conditions at Hartwood Home Farm, we seek to find the level of electricity prices required for small scale (<250 kW electrical capacity) combined heat and power (CHP) AD plants to break-even [30,31]. Such plants could in principle be supported by the land and livestock resources of many farms in the UK and the wider Global North, pursuant to sufficiently favourable prices for electricity and/or heat.

2.2. Model

Following consultations with the Hartwood Home Farm management, 20 practicable AD project feedstock mix scenarios were identified. Subsequently, five of these feedstock mix scenarios were selected for assessment in this paper. The five selected scenarios reflect end-member feedstock mixes within the range covered by feedstock options available to the farm. A key determinant of the economics of AD projects is the price for its products. In the current (July 2017) AD policy environment for Scotland and wider UK, there are four price dimensions for core small scale AD energy (i.e., electricity and heat) generation. These include: (1) the FIT for electricity generation; (2) the export price of electricity; (3) the RHI tariff for heat; and (4) the export price of heat. Figure 1 is a stylised schematic of a small scale CHP AD plant showing the relationship between these price dimensions. We do not explicitly account for the value of digestate as the current cost of applying digestate to the land is equivalent to its economic value [32]. However, use of inorganic fertiliser is minimised by the availability of digestate hence reducing the farm's overall operations costs.

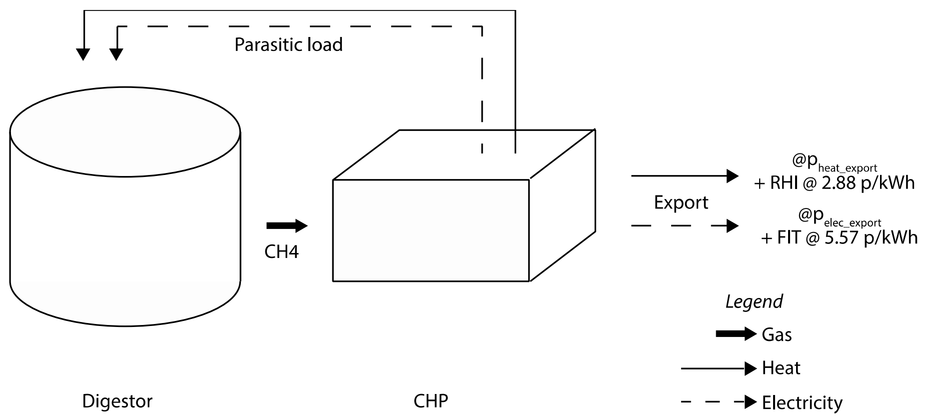


Figure 1. Stylised AD-CHP system modelled for our case study. CHP is Combined Heat and Power; 'RHI' is Renewable Heat Incentive; 'FIT' is Generation Feed-in-Tariff.

The purpose of this paper is to find the level of electricity prices needed for each of the 5 selected project scenarios to break even. Rather than use a deterministic framework as is often the case in the literature [31], we adopt a stochastic framework [20] to calculate these prices. The advantage of this approach is that it allows a robust determination of the expected range and level of electricity prices needed for a project scenario to break even, given the many chance possibilities of the realisation of key project parameters that are known to be stochastic. For each project scenario, we stochastically generate 10,000 separate random cases, each bearing the base features of the associated project scenario (e.g., type of feedstock used) but each having a separate random realisation of key stochastic project variables (e.g., yields of the feedstocks, plant runtime, plant efficiencies, etc.).

Let *i* represent any one of the 5 AD project Scenarios, *j* represent the 10,000 stochastically generated Cases for Scenario *i*, and *t* represent the 20 years of project lifetime for each Case *j* in project Scenario *i*. Also let *electricityPrice*(*i*,*j*) represent the break-even electricity price for Case *j* in Scenario *i*. For a given export price of heat and RHI tariff, we solve for *electricityPrice*(*i*,*j*) as follows:

$$\begin{matrix} Solve \\ electricityPrice(i,j) \end{matrix} \quad -totalCapitalCost(i,j) + \sum_{t=1}^{20} \frac{cashFlow(i,j,t)}{(1+discountRate)^{t-1}} = 0 \tag{1}$$

such that:

$$cashFlow(i,j,t) = postTaxProfit(i,j,t) + depreciationMachinery(i,j,t) + depreciationBuilding(i,j,t) \tag{2}$$

$$postTaxProfit(i,j,t) = preTaxProfit(i,j,t) - tax(i,j,t) \tag{3}$$

$$tax(i,j,t) = taxRate \times preTaxProfit(i,j,t) \tag{4}$$

$$\begin{aligned} preTaxProfit(i,j,t) \quad &= annualRevenue(i,j,t) - operationsCost(i,j,t) \\ &- depreciationMachinery(i,j,t) - depreciationBuilding(i,j,t) \end{aligned} \tag{5}$$

$$\begin{aligned} electricityRevenue(i,j,t) \quad &= (electricityPrice(i,j)/100) \\ &\times (1+electricityInflationRate)^{t-1} \times annualElectricityGeneration(i,j,t) \\ &\times (1 - parasiticLoadElectricity(i,j,t)) \end{aligned} \tag{6}$$

$$annualRevenues(i, j, t) = electricityRevenue(i, j, t) + heatRevenue(i, j, t) \quad (7)$$

$i \in \{1, \ldots, 5\}$ scenarios; $j \in \{1, \ldots, 10,000\}$ cases; $t \in \{1, \ldots, 20\}$ years where the parameters *discountRate, taxRate, electricityInflationRate* and *parasiticLoadElectricity* are given in percentages (%); *annualElectricityGeneration* is given in kWh and *electricityPrice* is given in p/kWh. All other parameters are given in £.

For a single Case *j*, Appendix C details a high-level description of our conceptual AD model and shows how key parameters are determined. *totalCapitalCost* in Equation (1) includes the initial and subsequent replacement costs of machinery and buildings over the lifetime of a Case *j* within a project Scenario *i* (see Appendix C). In capital budgeting analysis, depreciation costs are added to the post-tax cashflow as depreciation costs do not represent cash outflows (i.e., Equation (2)) [33]. They do however determine the amount of tax a project is charged hence are first subtracted from the pre-tax cashflow (i.e., Equation (5)) [33]. *operationsCost* involves the annual cost of labour, feedstock, water, transport, professional fees, etc. The feedstock quantities and biophysical properties of the 10,000 cases generated for each scenario and combination of prices are stochastically generated. Hence costs and revenues for each Case *j* in Scenario *i* in each year *t* would be different, leading to 10,000 different break-even electricity prices. This enables us to calculate the expected range and level of break-even electricity price for each of the 5 selected project scenarios, given the export price and RHI tariff for heat.

3. Data

3.1. Base Project Scenarios

The key determinants of the practicality of the five selected AD project scenarios are the current AD feedstock availability on the Hartwood Home Farm, and its capacity to generate additional feedstock in the future. These five scenarios have been selected in discussions with the farm managers from a range of further scenarios that could fit the farm's resources. The five scenarios were found to represent the most generic AD options for the farm. Table 2 details the base feedstock assumptions for each scenario and their base biophysical properties. Amounts and qualities of the manure and crop yields and qualities are based on the farm's experience and resources and figures for those marginal sites where the farm is located, as suggested in the leading farm management handbook for Scotland [34]. The location on marginal land restricts the crops that can be used, implies lower yields and qualities, especially for cereals. The marginal land does not affect manure qualities, but implies that farms in these specific areas typically rear cattle to make use of their grassland that cannot be cut for silage. Biogas yields are average values for the assumed feedstock qualities reported in the German literature that provides well-established experience-based figures for planning AD plants [35].

Scenario 1 is wholly dependent on feedstock that is already available to the farm in the form of solid manure and liquid cattle manure. Scenario 2 uses the same feedstock, with the same quantity of solid manure supply but the supply of cattle slurry is supplemented with slurry from a neighbouring farm, as is the case also for Scenarios 3 and 5. All the scenarios involve the use of cattle slurry, and all except Scenario 3 involve the use of solid manure. Scenarios 3, 4 and 5 involve the use of energy crops which are currently not grown on the Hartwood Home Farm. Allocation of land for producing these crops is therefore required. The size of land needed to produce these crops ranges from 12.5 ha for producing whole crop rye and fodder beet respectively in Scenario 4, to 25 ha for producing whole rye in Scenarios 3 and 5. Scenario 5 energy crops are a legume cereals mix with a lower yield per hectare.

The base biophysical properties of the feedstocks also reveal significant differences in dry matter percentages and importantly, biogas yields as established in the literature [35]. In particular, whole crop rye is predicted to have the highest biogas yield while cattle slurry has the lowest. Of the energy crops, fodder beet has the lowest biogas yield per dry matter. However, this crop has by far the highest fresh matter yield, which may compensate for its low biogas yield.

Table 2. Base feedstock assumptions for the five selected AD project scenarios derived from case study farm accounts, the Scottish farm management handbook [31] and German AD plant planning guideline [35].

Feedstock	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Solid manure					
Amount (tonnes/year)	3040	3040	-	3040	3040
Dry matter (%)	25	25	-	25	25
Biogas yield (m^3/tonne)	90	90	-	90	90
Liquid cattle manure					
Amount (tonnes/year)	1786	5118	5118	1786	5118
Dry matter (%)	10	10	10	10	10
Biogas yield (m^3/tonne)	25	25	25	25	25
Whole crop rye					
Amount (tonnes/year)	-	-	750	375	625
Dry matter (%)	-	-	33	33	33
Biogas yield (m^3/tonne)	-	-	200	200	200
Production area (ha)	-	-	25	12.5	25
Grass silage					
Amount (tonnes/year)	-	-	650	650	650
Dry matter (%)	-	-	30	30	30
Biogas yield (m^3/tonne)	-	-	185	185	185
Production area (ha)	-	-	20	20	20
Fodder beet					
Amount (tonnes/year)	-	-	-	1063	-
Dry matter (%)	-	-	-	18	-
Biogas yield (m^3/tonne)	-	-	-	85	-
Production area (ha)	-	-	-	12.5	-
Total tonnage	4826	8158	6628	7024	9543

3.2. Capital and Operating Expenditure Costs

The scale of the five selected AD project scenarios is shaped by the engineering specifications of the AD equipment and building infrastructure needed to process their feedstock. Table 3 details the capital costs of the AD equipment required for the various scenarios, which we derived through extrapolation of technological specifications and costs figures of comparable plants reported in handbooks [35], surveys [36], reports [31] and publicly available briefs of operating UK AD plants. We assume a continuous flow, single phase AD system for all the scenarios. CHP cost for Scenario 5 is highest due to the high tonnage and biogas yields of the feedstock it processes. However, due to the greater variety of feedstock in Scenario 4, the feedstock insertion equipment for that Scenario is about 14% higher than that of Scenario 5. As a result, the overall machinery capital cost in any installation or replacement cycle is higher in Scenario 4 than for other scenarios. Similarly, arising from the high cost of digester and fully covered digestate store, the cost of the building infrastructure for Scenario 4 is higher than the other scenarios. In the other scenarios, we assume a digestate store facility that is only partly covered (i.e., Scenarios 3 and 5), or uncovered (i.e., Scenarios 1 and 2) hence reducing building costs.

We assume a project life of 20 years and that the building infrastructure would outlive this period. No replacements are therefore needed for building infrastructure during project life of each project scenario. However, our base assumption for the life of the AD machinery is 7 years. There is therefore the need to replace machinery on two occasions in the life cycle of each project i.e., year 8 and year 14, after the initial installation in year 0.

Table 4 shows the annual recurrent costs for the various project scenarios, which we extrapolated from handbooks [31,35], surveys [36] surveys and complemented with data on comparable operations on Hartwood Farm. Scenarios 3, 4 and 5 have much higher recurrent costs due to use of energy crop feedstock. The cost of labour for feedstock insertion and plant operation differs across scenarios due to differences in labour requirements for processing feedstocks of different types and quantities. Other costs such as cost of digestate testing are independent of the feedstock types or quantities.

These are therefore equivalent across scenarios. Scenarios 2, 3 and 5 incur additional recurrent costs due to haulage of additional slurry from a neighbouring farm.

Table 3. One period capital expenditure for CHP machinery and building infrastructure for the various scenarios. Costs are re-incurred during replacement within project lifecycle.

Capital Expenditure	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Machinery, £					
CHP unit	144,000	210,000	210,000	256,000	260,000
Feedstock insertion	64,000	64,000	55,000	80,000	70,000
Total	208,000	274,000	265,000	336,000	330,000
Building and constr., £					
Digestate store	66,000	82,500	110,000	135,000	120,000
Digester	112,000	165,000	135,000	155,000	150,000
Manure storage	100,000	100,000	0.00	100,000	100,000
Silage storage	0.00	0.00	145,000	120,000	145,000
Additional storage	0.00	0.00	0.00	110,000	0.00
Access infrastructure	50,000	60,000	60,000	70,000	65,000
Planning expenses	12,000	14,000	14,000	18,000	16,000
Project management	20,000	20,000	20,000	20,000	20,000
Grid connection	12,000	12,000	12,000	12,000	12,000
Electrics	12,000	12,000	12,000	13,000	13,000
Health & Safety, etc	12,000	12,000	12,000	13,000	13,000
Total	396,000	477,500	520,000	766,000	654,000

Scenario 1: 110 kW CHP unit, 2200 m^3 digestate store, 750 m^3 digester, 1200 tonnes manure storage; Scenario 2: 140 kW CHP unit, 3300 m^3 digestate store, 1550 m^3 digester, 1200 tonnes manure storage; Scenario 3: 135 kW CHP unit, 2900 m^3 partly covered digestate store, 1000 m^3 digester, 1510 tonne silage; Scenario 4: 200 kW CHP unit, 2900 m^3 covered digestate store, 1300 m^3 digester, 1200 tonne manure storage, 1135 tonne silage store; Scenario 5: 210 kW CHP unit, 3800 m^3 partly covered digestate store, 1250 m^3 digester, 1200 tonne manure storage, 1385 tonne silage store.

Table 4. Annual operation costs of the various project scenarios, £.

£	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Loader	8000	8000	8000	8000	8000
Labour for feedstock insertion	2230	2230	1108	3322	3230
Labour for plant operation	9680	12,360	11,880	15,400	16,170
Slurry haulage	0.00	1530	1530	0.00	1530
Operating supplies	24,000	30,000	30,000	28,000	28,000
Maintenance and repairs	24,200	29,000	28,000	44,000	45,000
Digestate testing	300	300	300	300	300
Grass silage	0.00	0.00	13,200	13,200	13,200
Whole crop cereal silage	0.00	0.00	30,000	15,000	0.00
Whole crop cereal legume silage	0.00	0.00	0.00	0.00	25,000
Fodder beet	0.00	0.00	0.00	23,375	0.00
Total	68,410	83,420	124,018	150,597	140,430

3332 m^3 slurry haulage from neighbour; Operating supplies include fuel, lubricants.

3.3. Stochasticity in Parameters

As we adopt a stochastic framework, we introduce variation in the realisation of parameters for each year of the 10,000 cases generated for each project Scenario. Table 5 details the stochasticity of key parameters, their distributions and the range of values realisable in those distributions. The stochasticity of parameters, their distributions and values are sourced from the literature [20,35,37,38].

Table 5. Stochasticity, distributions and realisable values of parameters.

Parameter	Stochastic?	Distribution	Values
Feedstock quantity	Yes	Uniform	[Min = 90% of base quantity; Max = base quantity]; See Table 2 for base quantities of all feedstock
Biogas yield (m^3/tonne) Solid manure Liquid cattle manure Whole crop rye Grass silage Fodder beet	Yes	Triangular	 [min 60, mode 90, max 120] [min 20, mode 25; max 30] [min 170, mode 195, max 220] [min 170, mode 185, max 200] [min 75, mode 107.5, max 140]
Number of AD scenarios	No	-	5
Number of case studies	No	-	10,000
Planning horizon (years)	No	-	20
Lifetime machinery (years)	No	-	7
Runtime (h)	Yes	Triangular	[min 7000, mode 7500, max 8000]
Energy in methane (kWh/m^3)	No	-	11.2
Percent methane in biogas (%)	Yes	Uniform	[min 45, max 55]
Plant electricity efficiency (%)	Yes	Uniform	[min 33, max 45]
Plant heat efficiency (%)	Yes	Uniform	[min 38, max 48]
Overall plant inefficiency (%)	Yes	Uniform	[min 5, max 15]
Parasitic load, electricity (%)	Yes	Uniform	[min 6, max 10]
Parasitic load, heat (%)	Yes	Uniform	[min 20, max 40]
Annual operation cost, £	Yes	Uniform	[Min = 90% of base cost; Max = 110% × base cost]; see Table 4 for base costs
Inflation rate for electricity and heat price, (%)	No	-	5
Inflation rate for FIT and RHI level 1 and 2 tariffs, (%)	No	-	3
Money and finance			
Debt in capital expenditure (%)	No	-	0.0
Debt interest rate (%)	No	-	6.5
General inflation rate (%)	No	-	3
Repayment term (years)	No	-	10
Tax rate (%)	No	-	0.0

Annual operation cost is only stochastically generated for the first year in each Case and Scenario. The value realised by a case in the first year is inflated annually by the general rate of inflation.

4. Results

4.1. Base Results

The figures provided in Table 5 represent our base simulation assumptions for the various parameters, their stochasticity, distributions and values. Table 6 shows our base results. Three statistics are presented: (1) the mean break-even electricity prices; (2) the standard deviation of break-even electricity prices; and (3) *probability* of a project scenario breaking even or better if the current rates for FIT generation tariff (*GT*) and FIT export tariff (*ET*) for electricity are received i.e., P(GT+ET). These statistics are calculated for each project scenario, using a range of pre-determined export prices of heat (5–7 p/kWh) and the current heat RHI tariff of 2.88 p/kWh. The current FIT GT and ET for electricity are 5.57 p/kWh and 5.03 p/kWh respectively, giving a total electricity price of 10.60 p/kWh. To calculate P(GT+ET) for each project scenario, cases out of the 10,000 simulations whose breakeven prices are less than or equal to 10.60 p/kWh are marked as 1 (i.e., cost-effective cases), with others marked as 0 (i.e., non-cost-effective cases). The number of cases marked 1 as a proportion of the 10,000 simulations for a project scenario then represents the probability of breaking even or better for that scenario.

Table 6. Break-even electricity prices (p/kWh) in project Scenarios 1 to 5 for various prices of heat, given RHI tariff of 2.88 p/kWh.

Scenarios	Indicators	Heat Price (p/kWh)								
		5.00	**5.25**	**5.5**	**5.75**	**6**	**6.25**	**6.5**	**6.75**	**7.00**
Scenario 1	Mean	20.69	20.45	20.26	20.04	19.83	19.62	19.4	19.21	18.99
	S.D.	1.30	1.30	1.30	1.30	1.29	1.28	1.27	1.29	1.29
Scenario 2	Mean	20.25	20.04	19.82	19.63	19.41	19.19	18.98	18.78	18.55
	S.D.	1.18	1.18	1.18	1.17	1.19	1.19	1.19	1.18	1.18
Scenario 3	Mean	27.97	27.74	27.52	27.34	27.12	26.90	26.69	26.47	26.27
	S.D.	1.49	1.50	1.52	1.51	1.50	1.51	1.51	1.52	1.51
Scenario 4	Mean	21.06	20.82	20.62	20.39	20.20	19.99	19.77	19.56	19.36
	S.D.	1.21	1.22	1.20	1.20	1.21	1.22	1.22	1.22	1.20
Scenario 5	Mean	18.32	18.15	17.91	17.71	17.46	17.29	17.06	16.87	16.66
	S.D.	1.09	1.09	1.08	1.09	1.08	1.09	1.09	1.09	1.08
P(GT+ET) is 0.00 for all project scenarios, regardless of the heat price										

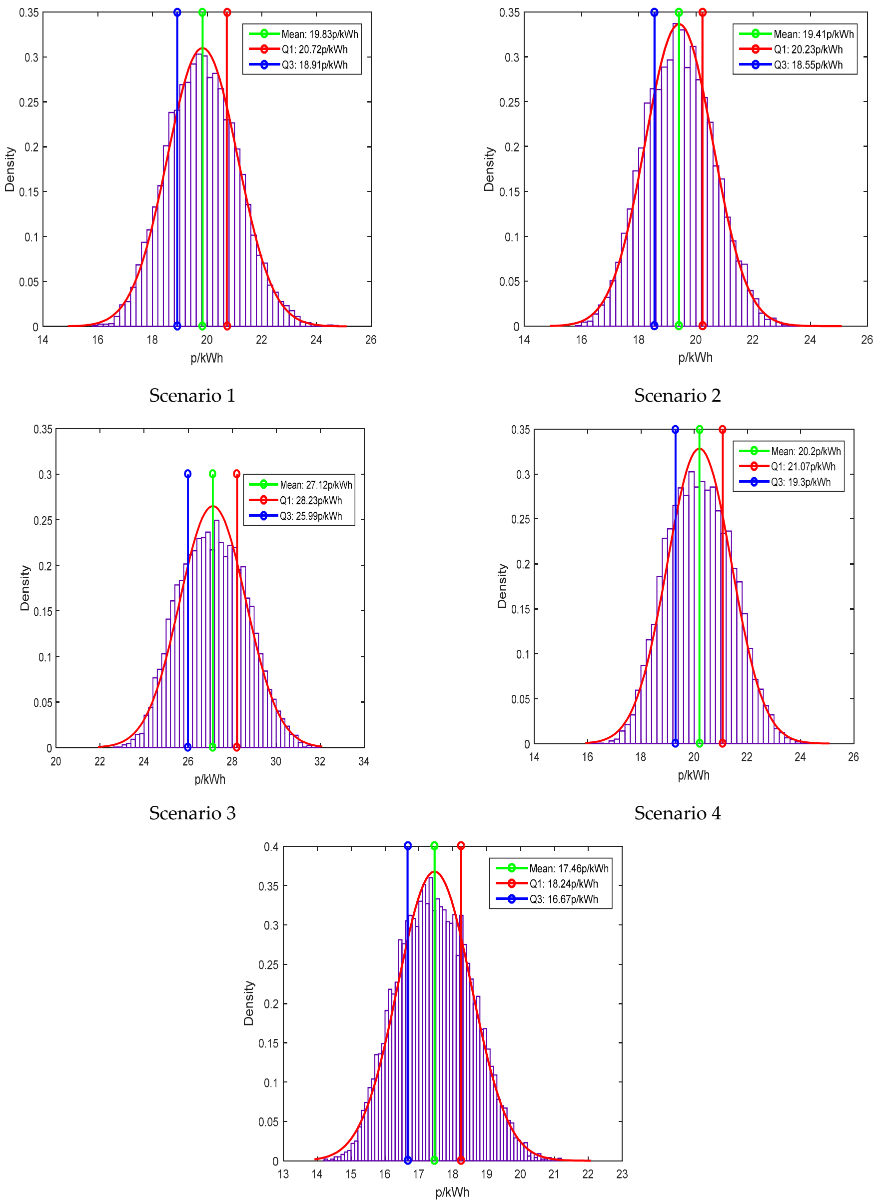
All values generated over 10,000 stochastic cases. Mean is average break-even electricity price. S.D. is its standard deviation. P(GT+ET) is probability of a Case *j* in project Scenario *i* breaking even or better if FIT generation tariff (GT) and export tariff (ET) are received.

The lower the breakeven electricity price, the more profitable a scenario. To the extent that a scenario is dependent on high electricity prices to break even, that scenario is less profitable. We therefore identify the relative profitabilities of the five project scenarios based on the level of electricity price each needs to break even. Table 6 shows that project Scenario 5 has the least break-even electricity prices. For a given export price of heat, this scenario has the lowest levels of breakeven electricity prices. For example, for heat price of 5.00 p/kWh, the mean break-even electricity price for Scenario 5 is only 18.32 p/kWh. For the same price of heat however, the mean break-even electricity price for Scenario 2 is 20.25 p/kWh, for Scenario 1 is 20.69 p/kWh, for Scenario 4 is 21.06 p/kWh and for Scenario 3 is up to 27.97 p/kWh. The profitability of the scenarios can therefore be ordered in descending order as follows; Scenario 5 (most profitable) > Scenario 2 > Scenario 1 > Scenario 4 > Scenario 3 (least profitable), although in some cases the difference in break-even electricity prices between scenarios is marginal (e.g., Scenario 1 vs. Scenario 4). Table 6 also shows that the export price of heat is an important determinant of the level of electricity prices needed for projects to break even, with increasing price of heat leading to decreasing breakeven electricity prices hence greater project profitability. Our base results show that with near certainty, none of our project scenarios is likely to break even or better as the probability of breaking even or better i.e., P(GT+ET) is 0.00 for all scenarios.

Table 7 shows the critical break-even prices of electricity for the various project scenarios given the prevailing market price of heat i.e., 6.00 p/kWh and RHI tariff of 2.88 p/kWh. These results show the likely outcome of the various scenarios if implemented in the current policy regime for small scale AD generated electricity. The associated distributions of the break-even electricity prices are shown in Figure 2. The result shows that based on the current FIT regime for electricity, none of the project scenarios is likely to breakeven (i.e., P(GT+ET) is 0.00 for all scenarios), with the minimum expected breakeven price needed for at least one project to breakeven being 17.46 p/kWh, and the maximum needed for all projects to breakeven or better being 27.12 p/kW.

Table 7. Critical break-even electricity prices (p/kWh) in project Scenarios 1 to 5, given prevailing heat price of 6.00 p/kWh and RHI tariff of 2.88 p/kWh. All values generated over 10,000 stochastic cases.

Scenarios	Mean	Median	S.D.	95% Confidence Interval	
				Lower	Upper
Scenario 1	19.83	19.81	1.29	19.81	19.86
Scenario 2	19.41	19.40	1.19	19.39	19.43
Scenario 3	27.12	27.12	1.51	27.09	27.15
Scenario 4	20.20	20.17	1.21	20.17	20.22
Scenario 5	17.46	17.44	1.08	17.44	17.48
P(GT+ET) is 0.00 for all project scenarios					



Scenario 1 Scenario 2 Scenario 3 Scenario 4 Scenario 5

Figure 2. Critical break-even electricity prices (p/kWh) in project Scenarios 1 to 5, given prevailing heat price of 6.00 p/kWh and RHI tariff of 2.88 p/kWh. All values generated over 10,000 stochastic cases.Q1 = first quartile; Q3 = third quartile.

4.2. Sensitivity Analysis

We conduct sensitivity analyses to investigate the extent to which some parameters influence results. The results discussed above are our base or benchmark results. The importance of a parameter is revealed by examining the magnitude and direction of change in the base results due to changes in the values defining the distributions of that parameter. Two settings are adopted for the sensitivity analyses, a high setting in which the base values defining the distributions of the investigated parameter are increased and a low setting where the values defining the investigated parameter distributions are decreased. Here, we only discuss sensitivity analyses for individual parameters separately, in the interest of space. For a detailed multi-dimensional sensitivity results, see Table A9 in the Appendix B.

4.2.1. Biogas Yield

We set modal biogas yield realisations in the low sensitivity analysis setting to about 80% of the base setting modal yield realisations. In the high sensitivity analysis setting, modal yield realisations are set to 120% of the base setting modal yield realisations (see Table A1 in Appendix A). The full set of results for the low and high biogas yield settings are presented in Tables A3 and A4 of Appendix B. Figure 3 shows a summary of the results for the prevailing price of heat only (i.e., 6.00 p/kWh).

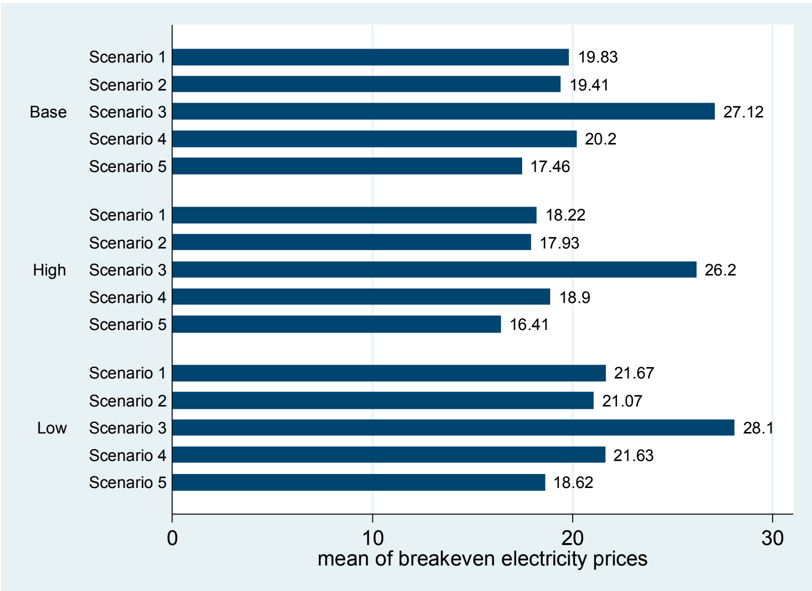


Figure 3. Sensitivity analysis for biogas yield of feedstock; showing mean break-even electricity prices and probability of breaking even or better for project Scenarios 1 to 5, given the prevailing price of heat (i.e., 6.00 p/kWh) and RHI tariff of 2.88 p/kWh. P(GT+ET) is 0.00 for all project scenarios.

The results show that biogas yield realisations are an important driver of the economics of the various project scenarios. In the low yield setting (i.e., 20% decrease in base modal biogas yield realisations), average increase in break-even electricity prices is about 7.03% (leading to worsening of project feasibility), although the impact on individual project scenarios is varied. For example, the increase in the break-even electricity price for project Scenario 3 is 3.61% (lowest) whilst the increase for project Scenario 1 is 9.28% (highest). In the high yield setting (i.e., 20% increase in base modal biogas yield realisations), average decrease in break-even electricity prices is about 6.32% (leading to enhancement of project feasibility), although the impact on individual project scenarios is varied. For example, the decrease in the break-even electricity prices for project Scenario 3 is only 3.39% (lowest) whilst the decrease in the break-even electricity prices for project Scenario 1 is 8.12% (highest).

The probability of a project scenario breaking even or better is zero in all settings. Project feasibility in all settings is therefore low, given the current generation FIT tariff and export tariff for electricity.

4.2.2. Runtime

Runtime refers to the accumulated annual operation hours of a project, the maximal being 8700 h. Projects are unlikely to achieve the maximal runtime due to project downtimes. The frequency and duration of downtimes may have implications for break-even electricity prices, hence project economics. The full set of results for the low and high runtime settings are presented in Tables A5 and A6 of Appendix B. Figure 4 below shows a summary of the results for the prevailing price of heat only (i.e., 6.00 p/kWh).

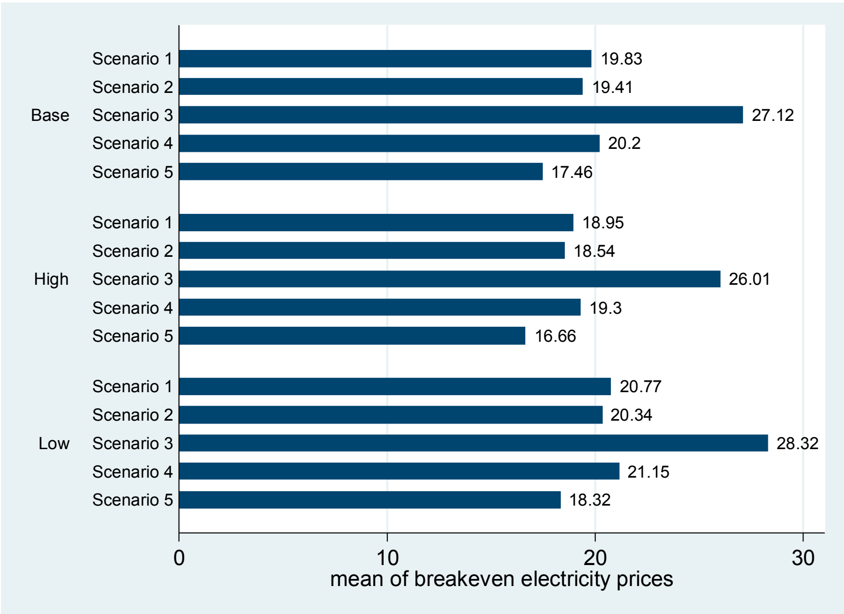


Figure 4. Sensitivity analysis for machinery runtime; showing mean break-even electricity prices and probability of breaking even or better for project Scenarios 1 to 5, given the prevailing price of heat (i.e., 6.00 p/kWh) and RHI tariff of 2.88 p/kWh. P(GT+ET) is 0.00 for all project scenarios.

The results show that runtime realisations are an important driver of the economics of the various scenarios. In the low runtime setting, average increase in break-even electricity prices is about 4.71%, leading to a worsening of project feasibility. In the high runtime setting, average decrease in break-even electricity prices is about 4.41%, leading to enhancement in project feasibility. The probability of a project scenario breaking even or better is zero in all settings. Project feasibility in all settings is therefore low, given the current generation FIT tariff and export tariff for electricity.

4.2.3. Debt and Equity Financing

The level of debt used in financing the capital expenditure of a project has implications for project costs. With debt financing, project costs are increased due to interest and principal payments over the term of the debt or project. In the base setting, we assumed 0.00% debt so that all 10,000 stochastically generated cases for each project scenario is financed via equity financing only. We now examine the impact of a 25.00% debt financing (moderate debt) and 75.00% debt financing (high debt) on break-even electricity prices. We assume that all debts are paid over a 10-year term at an interest rate of 6.5%. Principal and interest payments are equally spread over the debt term. The full set of results for the moderate and high debt settings are presented in Tables A7 and A8 of Appendix B. Figure 5 below shows a summary of the results for the prevailing price of heat only (i.e., 6.00 p/kWh).

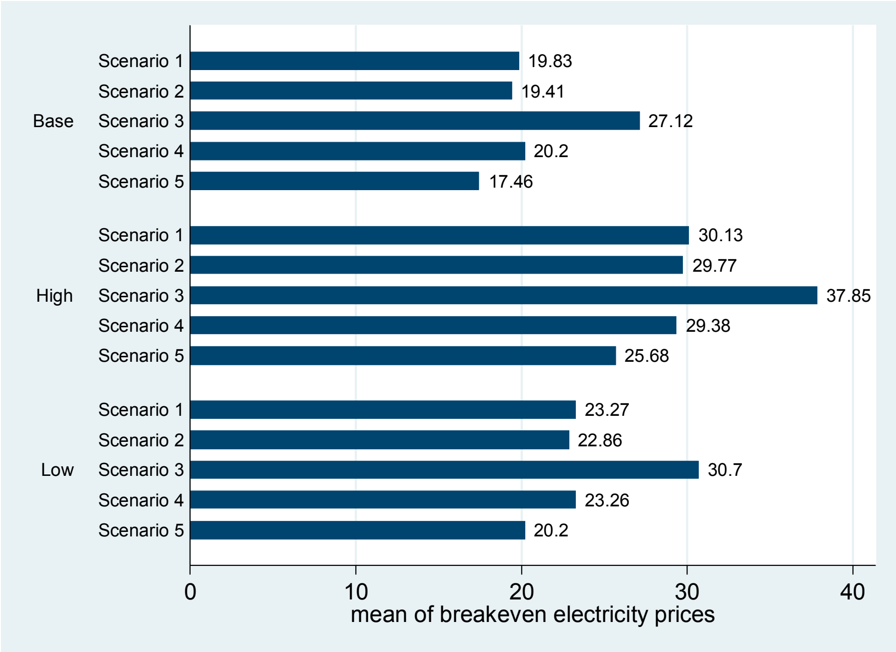


Figure 5. Sensitivity analysis for debt ratio; showing mean break-even electricity prices and probability of breaking even or better for project Scenarios 1 to 5, given the prevailing price of heat (i.e., 6.00 p/kWh) and RHI tariff of 2.88 p/kWh. P(GT+ET) is 0.00 for all project scenarios.

The results show that the amount of debt used in financing a project is an important determinant of break-even electricity prices, hence project profitability and feasibility. With only 25% debt financing, break-even electricity prices increased by about 15.83%, leading to worsening of project feasibility. With greater debt financing, these effects are even more pronounced. At 75% debt financing, break-even electricity prices increased by about 47.48% from the base results. The results also show the impact of debt on the likelihood of needing FIT support to break even. At only 25% debt financing, all project scenarios are likely not to break even with near certainty. This situation is made more pronounced at higher debt financing of 75%.

5. Discussion and Conclusions

We assessed the potential of small scale CHP AD projects breaking even or better, given the current (July 2017) UK FIT and RHI policy regime for small scale AD, using five realistic feedstock scenarios for a representative temperate latitude marginal farm land in Scotland's Central Belt. As expected, we find in our sensitivity analyses that the yield of biogas, degree of runtime and the debt/equity structure of projects are important determinants of the level of electricity prices required for CHP AD projects to break even or better on UK marginal land.

In our base projections, the critical break-even electricity prices, gross of any electricity price support mechanisms, ranges from 17.46 p/kWh to 27.12 p/kWh, given current RHI tariff support of 2.88 p/kWh and current market heat price of about 6.00 p/kWh. When the current electricity FIT tariff of 5.57 p/kWh is accounted for, the break-even shortfall of about 11.89 p/kWh to 21.55 p/kWh is still in excess of the current electricity export tariff level of 5.03 p/kWh, meaning that reliance on the electricity export tariff rather than alternate arrangements—such as a power purchase agreement (PPA) or trading on the day-ahead wholesale market—is not a viable option for AD on marginal land. Even so, given that UK wholesale prices of electricity have rarely strayed outside of the range between 3.00 and 5.00 p/kWh over the past two years, the prospects for breaking even by making use of alternate trading mechanisms are also poor. Current retail prices for electricity in the UK are about 9–12 p/kWh. Only if a substantial proportion of the net electricity generated was to be used on-site (rather than exported) to displace power previously purchased at these retail prices, would marginal AD be financially viable under current market conditions using the most viable of the project feedstock mixes modelled.

For marginal land to be used for small-scale on-site energy generation and export as explored here, generation FIT would need to be raised by at least 6.86 p/kWh and as much as 16.52 p/kWh above present levels of 5.57 p/kWh, given the current electricity export tariff of 5.03 p/kWh, current RHI tariff of 2.88 p/kWh and current heat price of about 6.00 p/kWh. However, this assumes that AD plants making use of grass silage remain eligible for RHI support. We note that the altered status of grass silage in new UK energy legislation would make our scenarios with bio-energy crops ineligible for RHI support. Grass is one of the major crops from marginal land in temperate latitudes usable for AD. However, because biogas yields are critical for plant profitability, such grass needs to achieve high biogas yields, which is likely to be more difficult on marginal land. A policy option in the UK context, but also elsewhere, would be to categorise crops from marginal land as waste, and provide explicit support (e.g., through mechanisms such as the FIT and RHI) for their use as feedstock in AD. This would require careful design of policy to ensure that the crops are not substituted for by crops from more productive land that have better biogas yields.

We conclude that the use of marginal land to generate power using small-scale CHP AD for export purposes is presently unviable in the UK and very likely in other comparable locations. More generally, in view of current and ongoing declines in costs of generating electricity from other renewables technologies, notably solar and wind, we conclude that the use of marginal land to generate power using small-scale CHP AD at temperate latitudes is only cost-effective where a large proportion of the electricity generated is used locally to displace electricity otherwise paid for at retail prices. We therefore expect no great expansion of the agricultural AD sector on marginal land in the UK and in comparable locations. However, conditions for AD on marginal land may improve, if agricultural policy reform results in reduced input costs (e.g., through payments for energy crops grown on marginal land) and capital subsidies (e.g., through rural development programmes) in marginal farming areas. Given the socio-economic deprivation of communities in marginal land areas, such support may also help improve employment opportunities, reduce energy costs, increase incomes and improve the skills of people living in such communities.

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Author Contributions: The three authors contributed equally to the study conception and design of the research question. The first author was responsible for economic modelling and contributed about 40% of the manuscript write-up and revision. The second author was responsible for data collection and verification, and contributed about 30% of the manuscript write-up and revision. The third author was responsible for situating the research question in the context of UK energy policy and contributed about 30% of the manuscript write-up and revision.

Conflicts of Interest: The authors declare no conflict of interest.

Appendix A

Table A1. Triangular distribution values for sensitivity analysis of feedstock biogas yield. Showing base, low and high yield settings for stochastic biogas yield realisations.

Feedstock	Base Setting	Low Setting	High Setting
Solid manure	[min 60, mode 90, max 120]	[min 60, mode 72, max 120]	[min 60, mode 108, max 120]
Liquid cattle manure	[min 20, mode 25; max 30]	[min 20, mode 22; max 30]	[min 20, mode 28; max 30]
Whole crop rye	[min 170, mode 195, max 220]	[min 170, mode 180, max 220]	[min 170, mode 2010, max 220]
Grass silage	[min 170, mode 185, max 200]	[min 170, mode 176, max 200]	[min 170, mode 194, max 200]
Fodder beet	[min 75, mode 107.5, max 140]	[min 75, mode 88, max 140]	[min 75, mode 127, max 140]

Table A2. Triangular distribution values for sensitivity analysis of runtime (h). Showing base, low and high runtime settings for stochastic runtime realisations.

Range	Base Setting	Low Setting	High Setting
Min	7000	7000	7500
Mode	7500	7250	7750
Maximum	8000	7500	8000

Appendix B

Table A3. Low biogas yield setting: Break-even electricity prices (p/kWh) in project Scenarios 1 to 5 for various prices of heat, given RHI tariff of 2.88 p/kWh.

Scenarios	Indicators	Heat (p/kWh)								
		5.00	5.25	5.5	5.75	6	6.25	6.5	6.75	7.00
Scenario 1	Mean	22.53	22.29	22.09	21.88	21.67	21.45	21.24	21.05	20.83
	S.D.	1.45	1.45	1.45	1.45	1.43	1.43	1.41	1.44	1.43
Scenario 2	Mean	21.91	21.70	21.48	21.29	21.07	20.85	20.64	20.45	20.21
	S.D.	1.30	1.30	1.29	1.28	1.30	1.30	1.30	1.29	1.30
Scenario 3	Mean	28.94	28.71	28.50	28.32	28.10	27.87	27.66	27.44	27.24
	S.D.	1.54	1.54	1.57	1.56	1.55	1.55	1.55	1.56	1.56
Scenario 4	Mean	22.50	22.25	22.05	21.82	21.63	21.42	21.20	20.99	20.80
	S.D.	1.29	1.30	1.28	1.28	1.30	1.30	1.30	1.30	1.29
Scenario 5	Mean	19.47	19.30	19.06	18.86	18.62	18.44	18.22	18.03	17.81
	S.D.	1.16	1.15	1.14	1.15	1.15	1.15	1.15	1.15	1.14
P(GT+ET) is 0.00 for all project scenarios, regardless of the heat price										

All values generated over 10,000 stochastic cases. Mean is average break-even electricity price. S.D. is its standard deviation. P(GT+ET) is probability of a Case *j* in project Scenario *i* breaking even or better if FIT generation tariff (GT) and export tariff (ET) are received.

Table A4. High biogas yield setting: Break-even electricity prices (p/kWh) in project Scenarios 1 to 5 for various prices of heat, given RHI tariff of 2.88 p/kWh.

Scenarios	Indicators	Heat (p/kWh)								
		5.00	5.25	5.5	5.75	6	6.25	6.5	6.75	7.00
Scenario 1	Mean	19.07	18.84	18.64	18.43	18.22	18.00	17.79	17.59	17.38
	S.D.	1.22	1.22	1.23	1.22	1.21	1.20	1.19	1.21	1.21
Scenario 2	Mean	18.78	18.56	18.35	18.15	17.93	17.71	17.50	17.31	17.07
	S.D.	1.12	1.12	1.12	1.11	1.12	1.12	1.12	1.11	1.12
Scenario 3	Mean	27.04	26.81	26.60	26.42	26.20	25.98	25.76	25.54	25.34
	S.D.	1.45	1.46	1.48	1.47	1.47	1.47	1.47	1.47	1.47
Scenario 4	Mean	19.77	19.53	19.32	19.10	18.90	18.69	18.47	18.27	18.07
	S.D.	1.15	1.16	1.15	1.15	1.16	1.16	1.16	1.16	1.15
Scenario 5	Mean	17.26	17.09	16.85	16.65	16.41	16.23	16.01	15.82	15.60
	S.D.	1.05	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.03
P(GT+ET) is 0.00 for all project scenarios, regardless of the heat price										

All values generated over 10,000 stochastic cases. Mean is average break-even electricity price. S.D. is its standard deviation. P(GT+ET) is probability of a Case *j* in project Scenario *i* breaking even or better if FIT generation tariff (GT) and export tariff (ET) are received.

Table A5. Low runtime setting: Break-even electricity prices (p/kWh) in project Scenarios 1 to 5 for various prices of heat, given RHI tariff of 2.88 p/kWh.

Scenarios	Indicators	Heat (p/kWh)								
		5.00	5.25	5.5	5.75	6	6.25	6.5	6.75	7.00
Scenario 1	Mean	21.63	21.39	21.20	20.98	20.77	20.56	20.34	20.15	19.94
	S.D.	1.34	1.34	1.34	1.33	1.33	1.32	1.30	1.33	1.32
Scenario 2	Mean	21.18	20.96	20.75	20.55	20.34	20.11	19.90	19.71	19.47
	S.D.	1.22	1.22	1.21	1.20	1.22	1.22	1.22	1.21	1.21
Scenario 3	Mean	29.16	28.93	28.71	28.53	28.32	28.09	27.88	27.66	27.46
	S.D.	1.54	1.54	1.56	1.55	1.55	1.55	1.55	1.56	1.55
Scenario 4	Mean	22.02	21.77	21.57	21.35	21.15	20.94	20.72	20.52	20.32
	S.D.	1.25	1.25	1.24	1.24	1.25	1.25	1.25	1.25	1.24
Scenario 5	Mean	19.18	19.01	18.77	18.57	18.32	18.15	17.92	17.73	17.52
	S.D.	1.12	1.12	1.11	1.12	1.11	1.11	1.12	1.12	1.11
P(GT+ET) is 0.00 for all project scenarios, regardless of the heat price										

All values generated over 10,000 stochastic cases. Mean is average break-even electricity price. S.D. is its standard deviation. P(GT+ET) is probability of a Case *j* in project Scenario *i* breaking even or better if FIT generation tariff (GT) and export tariff (ET) are received.

Table A6. High runtime setting: Break-even electricity prices (p/kWh) in project Scenarios 1 to 5 for various prices of heat, given RHI tariff of 2.88 p/kWh.

Scenarios	Indicators	Heat (p/kWh)								
		5.00	5.25	5.5	5.75	6	6.25	6.5	6.75	7.00
Scenario 1	Mean	19.81	19.57	19.38	19.16	18.95	18.74	18.52	18.33	18.11
	S.D.	1.25	1.25	1.25	1.25	1.24	1.23	1.22	1.24	1.24
Scenario 2	Mean	19.39	19.17	18.96	18.76	18.54	18.32	18.11	17.92	17.68
	S.D.	1.14	1.14	1.13	1.12	1.14	1.14	1.14	1.13	1.13
Scenario 3	Mean	26.85	26.62	26.41	26.23	26.01	25.78	25.57	25.35	25.15
	S.D.	1.43	1.44	1.46	1.45	1.44	1.44	1.45	1.45	1.45
Scenario 4	Mean	20.17	19.93	19.72	19.50	19.30	19.09	18.88	18.67	18.47
	S.D.	1.16	1.17	1.15	1.15	1.17	1.17	1.17	1.17	1.15
Scenario 5	Mean	17.51	17.34	17.10	16.90	16.66	16.48	16.26	16.07	15.85
	S.D.	1.05	1.04	1.04	1.05	1.04	1.04	1.04	1.05	1.03
P(GT+ET) is 0.00 for all project scenarios, regardless of the heat price										

All values generated over 10,000 stochastic cases. Mean is average break-even electricity price. S.D. is its standard deviation. P(GT+ET) is probability of a Case *j* in project Scenario *i* breaking even or better if FIT generation tariff (GT) and export tariff (ET) are received.

Table A7. 25% debt financing: Break-even electricity prices (p/kWh) in project Scenarios 1 to 5 for various prices of heat, given RHI tariff of 2.88 p/kWh.

Scenarios	Indicators	Heat (p/kWh)								
		5.00	5.25	5.5	5.75	6	6.25	6.5	6.75	7.00
Scenario 1	Mean	24.12	23.88	23.69	23.48	23.27	23.05	22.84	22.64	22.43
	S.D.	1.40	1.40	1.40	1.40	1.39	1.38	1.36	1.39	1.38
Scenario 2	Mean	23.71	23.49	23.27	23.08	22.86	22.64	22.43	22.24	22.00
	S.D.	1.27	1.27	1.26	1.26	1.27	1.27	1.27	1.26	1.27
Scenario 3	Mean	31.54	31.31	31.10	30.92	30.70	30.48	30.26	30.04	29.84
	S.D.	1.55	1.55	1.58	1.57	1.56	1.56	1.56	1.57	1.57
Scenario 4	Mean	24.12	23.88	23.68	23.45	23.26	23.05	22.83	22.62	22.43
	S.D.	1.27	1.27	1.26	1.26	1.27	1.28	1.27	1.27	1.26
Scenario 5	Mean	21.06	20.89	20.65	20.45	20.20	20.03	19.80	19.61	19.40
	S.D.	1.14	1.14	1.13	1.14	1.13	1.13	1.14	1.14	1.12
P(GT+ET) is 0.00 for all project scenarios, regardless of the heat price										

All values generated over 10,000 stochastic cases. Mean is average break-even electricity price. S.D. is its standard deviation. P(GT+ET) is probability of a Case *j* in project Scenario *i* breaking even or better if FIT generation tariff (GT) and export tariff (ET) are received.

Table A8. 75% debt financing: Break-even electricity prices (p/kWh) in project Scenarios 1 to 5 for various prices of heat, given RHI tariff of 2.88 p/kWh.

Scenarios	Indicators	Heat (p/kWh)								
		5.00	5.25	5.5	5.75	6	6.25	6.5	6.75	7.00
Scenario 1	Mean	30.99	30.75	30.56	30.34	30.13	29.92	29.70	29.51	29.29
	S.D.	1.61	1.61	1.61	1.61	1.60	1.59	1.57	1.59	1.59
Scenario 2	Mean	30.61	30.39	30.18	29.99	29.77	29.55	29.34	29.14	28.90
	S.D.	1.46	1.45	1.45	1.44	1.46	1.46	1.45	1.45	1.45
Scenario 3	Mean	38.69	38.46	38.25	38.07	37.85	37.63	37.41	37.19	36.99
	S.D.	1.68	1.68	1.71	1.69	1.69	1.69	1.69	1.70	1.69
Scenario 4	Mean	30.24	30.00	29.80	29.57	29.38	29.17	28.95	28.74	28.55
	S.D.	1.39	1.40	1.38	1.39	1.40	1.40	1.39	1.40	1.38
Scenario 5	Mean	26.54	26.37	26.13	25.93	25.68	25.51	25.28	25.09	24.88
	S.D.	1.25	1.25	1.24	1.25	1.24	1.24	1.24	1.25	1.23
P(GT+ET) is 0.00 for all project scenarios, regardless of the heat price										

All values generated over 10,000 stochastic cases. Mean is average break-even electricity price. S.D. is its standard deviation. P(GT+ET) is probability of a Case *j* in project Scenario *i* breaking even or better if FIT generation tariff (GT) and export tariff (ET) are received.

Table A9. A three-dimensional sensitivity analysis of Break-even electricity prices (p/kWh) for Project Scenario 5, showing the joint impact of changes in project debt level, biogas yield and annual runtimes. All results based on heat price of 6.00 p/kWh, RHI tariff level of 2.88 p/kWh minimum and maximum triangular distribution levels of 7000 h and 8000 h respectively for runtime.

Debt Level	Δ Modal Biogas Yield	Modal Runtime (h)										
		7000	7100	7200	7300	7400	7500	7600	7700	7800	7900	8000
	−20.00%	19.25	19.10	19.00	18.87	18.76	18.63	18.52	18.42	18.30	18.19	18.07
	−17.50%	18.82	18.72	18.60	18.46	18.35	18.25	18.11	18.03	17.90	17.79	17.70
	−15.00%	18.45	18.32	18.20	18.08	17.97	17.89	17.74	17.64	17.51	17.42	17.31
0%	0.00%	18.05	17.94	17.83	17.70	17.63	17.49	17.39	17.24	17.17	17.05	16.96
	+15.00%	17.70	17.58	17.45	17.35	17.23	17.12	17.00	16.90	16.80	16.70	16.60
	+17.50%	17.32	17.23	17.11	17.00	16.88	16.77	16.68	16.56	16.48	16.35	16.25
	+20.00%	16.97	16.87	16.77	16.65	16.55	16.45	16.33	16.23	16.13	16.01	15.91
	−20.00%	22.18	22.03	21.91	21.78	21.65	21.53	21.38	21.24	21.12	21.00	20.88
	−17.50%	21.72	21.58	21.44	21.31	21.20	21.09	20.95	20.82	20.70	20.56	20.43
	−15.00%	21.30	21.15	21.01	20.90	20.77	20.63	20.51	20.39	20.27	20.15	20.04
25%	0.00%	20.85	20.74	20.61	20.49	20.35	20.22	20.11	19.99	19.87	19.75	19.64
	+15.00%	20.43	20.31	20.21	20.06	19.95	19.82	19.72	19.59	19.46	19.34	19.25
	+17.50%	20.06	19.94	19.83	19.67	19.56	19.43	19.31	19.18	19.09	18.97	18.85
	+20.00%	19.67	19.55	19.42	19.31	19.18	19.07	18.94	18.84	18.72	18.59	18.48
	−20.00%	25.11	24.95	24.82	24.68	24.53	24.37	24.26	24.09	23.96	23.83	23.67
	−17.50%	24.60	24.44	24.31	24.16	24.03	23.91	23.77	23.61	23.49	23.34	23.22
	−15.00%	24.13	23.96	23.84	23.70	23.56	23.42	23.28	23.15	23.03	22.88	22.76
50%	0.00%	23.66	23.53	23.38	23.21	23.12	22.95	22.83	22.69	22.55	22.43	22.31
	+15.00%	23.22	23.07	22.93	22.79	22.66	22.53	22.41	22.26	22.13	22.01	21.87
	+17.50%	22.75	22.61	22.49	22.36	22.23	22.08	21.95	21.83	21.71	21.58	21.45
	+20.00%	22.34	22.22	22.08	21.91	21.79	21.67	21.55	21.44	21.31	21.17	21.05
	−20.00%	28.04	27.89	27.71	27.58	27.42	27.24	27.08	26.94	26.78	26.65	26.48
	−17.50%	27.49	27.33	27.17	27.02	26.87	26.72	26.56	26.44	26.25	26.12	25.96
	−15.00%	26.96	26.82	26.66	26.52	26.36	26.20	26.05	25.89	25.77	25.63	25.49
75%	0.00%	26.47	26.32	26.15	26.01	25.85	25.71	25.56	25.41	25.27	25.12	24.98
	+15.00%	25.97	25.81	25.66	25.52	25.40	25.21	25.10	24.94	24.82	24.65	24.52
	+17.50%	25.50	25.35	25.19	25.06	24.89	24.76	24.62	24.49	24.32	24.18	24.05
	+20.00%	25.03	24.87	24.73	24.61	24.45	24.29	24.17	24.02	23.89	23.74	23.62
	−20.00%	30.97	30.79	30.61	30.44	30.27	30.12	29.92	29.80	29.63	29.46	29.29
	−17.50%	30.38	30.20	30.04	29.86	29.70	29.54	29.36	29.21	29.05	28.90	28.74
	−15.00%	29.82	29.64	29.48	29.32	29.14	28.98	28.84	28.68	28.51	28.34	28.21
100%	0.00%	29.26	29.08	28.94	28.80	28.61	28.47	28.32	28.13	27.99	27.82	27.66
	+15.00%	28.74	28.58	28.41	28.26	28.08	27.93	27.78	27.61	27.48	27.31	27.19
	+17.50%	28.22	28.08	27.90	27.72	27.59	27.42	27.28	27.12	26.94	26.82	26.65
	+20.00%	27.73	27.55	27.41	27.24	27.07	26.93	26.78	26.62	26.49	26.35	26.19

Please note that results are stochastically generated so that whilst levels with base and other sensitivity results are comparable, they may not be exact.

Appendix C

Appendix C.1 A Conceptual AD Plant Model

The following exposition is based on the NNFCC model, with some modifications where appropriate.

Appendix C.2 Feedstock and Biogas

Let f represent all feedstock types used by a single AD plant. The total annual biogas produced by the plant from its feedstock is given by;

$$annualBiogasProduction = \sum_{f} (feedTonnage(f) \times yield(f)) \tag{A1}$$

where *annualBiogasProduction* is volume produced of biogas in m^3, *feedTonnage* is the processed mass of feedstock type f in tonnes, *yield* is the yield of a feedstock in m^3/tonne.

Appendix C.3 Revenues

Let *energyMethane* represent the amount of energy in a m^3 of methane, measured in m^3/kWh, and let %*methaneInBiogas* represent the percentage amount of methane in a m^3 of biogas, measured as a percentage (%). Then the energy content of a m^3 of biogas is given by:

$$energyContentBiogas = \%methaneInBiogas \times energyMethane \tag{A2}$$

where *energyContentBiogas* is given in kWh/m^3. Inefficiencies in the conversion of biogas to energy mean an AD plant realises less than the full potential of energy in the biogas it produces. Now, let *lossInefficiency* represent the percentage inefficiency of an AD plant arising from loss of energy to the environment, let *electricityConversionEfficiency* represent the inefficiency arising from loss of energy due to conversion of methane to electricity and *heatConversionEfficiency* represent the inefficiency arising from loss of energy due to conversion of methane to heat. Given these inefficiencies the electricity and heat output of a m^3 of biogas is given by:

$$electricityConversionEfficiency \times (1 - lossInefficiency) \times energyContentBiogas \tag{A3}$$

$$heatOutput = heatConversionEfficiency \times (1 - lossInefficiency) \times energyContentBiogas \tag{A4}$$

where both *electricityOutput* and *heatOutput* are given in kWh/m^3. The total annual electricity and heat generation of an AD plant is then given by:

$$annualElectricityGenerated = electricityOutput \times annualBiogasProduction \tag{A5}$$

$$annualHeatGenerated = heatOutput \times annualBiogasProduction \tag{A6}$$

where *annualElectricityGenerated* and *annualHeatGenerated* are given in kWh. Let *electricityPrice* and *heatPrice* represent the price of electricity and heat respectively, all given in £/kWh. The revenue accrued from electricity and heat sales of an AD plant in a given period is given by the following;

$$electricityRevenue = electricityPrice \times (1 - parasiticLoadElectricity) \times annualElectricityGeneration \tag{A7}$$

$$heatRevenue = (heatPrice + RHI) \times (1 - parasiticLoadHeat) \times annualHeatGeneration \tag{A8}$$

where *parasiticLoadElectricity* and *parasiticLoadHeat* are the percentages of annually generated electricity and heat that are used internally by the AD plant to sustain its operation. *runtime* is the total number of operational hours in a year. Both *electricityRevenue* and *heatRevenue* are given in £. The total revenue from an AD operation is given by:

$$annualRevenues = electricityRevenue + heatRevenue \tag{A9}$$

where *annualRevenues* is given in £.

Appendix C.4 Capital Investment Costs

The capital costs of machinery (i.e., CHP unit, heat exchanger, biogas scrubber, etc.) and building infrastructure (i.e., AD digester, separator, feedstock storage, etc.) are important determinants of the economic feasibility of an AD project. Depending on the planning horizon of a project, machinery and/or building infrastructure may require periodic replacements. Let *planningHorizon*, *lifetimeMachinery* and *lifetimeBuilding* represent the planning horizon of an AD project, the lifetime of its machinery and the lifetime of its building infrastructure respectively. Also let *replacementYearsMachinery* and *replacementYearsBuilding* represent the replacement years of machinery and building infrastructure respectively such that:

$replacementYearsMachinery \in \{1, t_1, t_2, t_3, \ldots t_j)$ where $t_j - t_{j-1} = lifetimeMachinery$ and $replacementYearsBuilding \in \{1, f_1, f_2, f_3, \ldots f_p)$ where $f_p - f_p - 1 = lifetimeBuilding;$ $tj \leq planningHorizon; fp \leq planningHorizon$

Replacement year 1 in both replacement year series represents the initial project year for which installation of machinery and building infrastructure is a requirement. The interval between replacement years of a unit is the economic lifetime of that unit. For a machinery lifetime of 7 years in a 20 year planning horizon project for example, the initial installation and replacement years would be in years 1, 8 and 15. Given the above, let *costMachinery* and *costBuilding* represent the one period cost of machinery and building infrastructure respectively. Then the total cost of machinery and building infrastructure over the planning horizon of a project is calculated as follows:

$$totalCostMachinery = \sum_{replacementYearMachinery}^{planningHorizon} \left(\frac{costMachinery \times (1 + inflation)^{replacementYearMachinery}}{(1 + discountRate)^{replacementYearMachinery - 1}} \right) \tag{A10}$$

$$totalCostBuilding = \sum_{replacementYearBuilding}^{planningHorizon} \left(\frac{costBuilding \times (1 + inflation)^{replacementYearBuilding}}{(1 + discountRate)^{replacementYearBuilding - 1}} \right) \tag{A11}$$

where *discountRate* and *inflation* are the discount rate and inflation rate, respectively. Consequently the total capital cost of a project is given by:

$$totalCapitalCost = totalCostMachinery + totalCostBuilding \tag{A12}$$

totalCapitalCost is the amount needed to cover the costs of an AD project's initial machinery and building infrastructure, as well as subsequent such investments within the project's planning horizon. In year 1, if *totalCapitalCost* is held in savings offering interest rate of *discountRate (%)*, or invested in a project offering at least *discountRate (%)* return, it is able to meet these capital costs over the project cycle.

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