Potential for Microgeneration Study and Analysis

Final Report

14th November 2005

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Caveats

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgment when using it.

The authors do not make any representation of warranty, express or implied as to the accuracy or completeness of the report. A central element of this report, namely a technology uptake model spanning the period of time out to 2050, is by its nature open to significant uncertainty. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report.

The views and judgments expressed here are the opinions of the authors and do not necessarily reflect those of the DTI.

Index

Executive Summary

Background

- The Energy Saving Trust, in conjunction with Element Energy Limited, E-Connect and Cambridge University Faculty of Economics, has been commissioned by the DTI to study the UK potential for microgeneration technologies. The technologies included in this study are:
  - solar photovoltaics (PV);
  - wind turbines;
  - small hydro;
  - active solar water heating *;
  - ground source heat pumps (GSHP);
  - bio-energy;
  - small CHP (renewable and non-renewable); and
  - hydrogen energy and fuel cells.
- Microgeneration is defined as any technology, connected to the distribution network (if electric) and with a capacity below 50-100kW. Most domestic installations will be below 3kWe, though thermal systems could be larger.
- Microgeneration could deliver significant efficiency and CO_2 benefits, through increased use of renewables, utilisation of "waste" heat from electricity generation or renewable heating fuels, and avoidance of losses in the electricity transmission and distribution system.
- For microgeneration to have an impact on the UK electricity system, units must be installed by consumers in their millions. This will require a new highly decentralised approach to energy planning and policy. In addition a new understanding of the likely interaction between microgeneration technology and its multitude of potential end users (the general public) must be developed.

(*) Active solar water heating is sometimes referred to as 'active solar heating' or 'ASH' in this report.

The UK Microgeneration industry overview, reveals a young but growing industry.

Current status of microgeneration in the UK

- An industry consultation was used to feed into an assessment of the current status of microgeneration, and more detailed comments taken from a series of roundtables organised independently of this project. .
- There are currently less than 100,000 microgeneration installations in the UK (of which most are solar water heaters installed pre-2000). Level of grant funding is closely correlated with the annual number of installations.
- The sectors seeing the most yearly installations are PV and solar water heating, in response to generous grant schemes. The yearly installations in ground source heat pumps and small wind turbines is also increasing rapidly stimulated by the Clear Skies SCHRI program and rapid cost reductions.
- MicroCHP is only just beginning to enter the market, but there is a very large technical effort on both Stirling engine and fuel cell technologies.

Perceived barriers to the introduction of Microgeneration

- The most commonly perceived barriers to the introduction of microgeneration are: legislation, high cost and the level of consumer awareness.
- The “legislation” barrier refers to problems with planning permission and “expensive metering” (also interpreted as low value of exported electricity), and the lack of targets and incentives for renewable heat.
- High cost of technology is an important barrier: most suggestions for overcoming this relate to the provision of appropriate grant schemes although it is generally recognised that grant support cannot be a long term mechanism.
- Most suggestions on awareness focus on establishing a centrally co-ordinated program to improve information and advice to installers and end users of microgeneration technologies.

Overview of approach to UK market simulation.

The cost of energy from each technology is modelled for the period 2005 – 2050:

- The cost of each technology installed is predicted for the period 2005 – 2050. This is achieved using learning curve analysis.
- The capital installed costs are used to calculate the cost of energy from each system. This is based on factors such as system lifetime and efficiency, and the inclusion of running costs such as maintenance and fuel where applicable.
- The cost of energy values allow prediction of the date at which a technology becomes cost effective.

Application to the UK market:

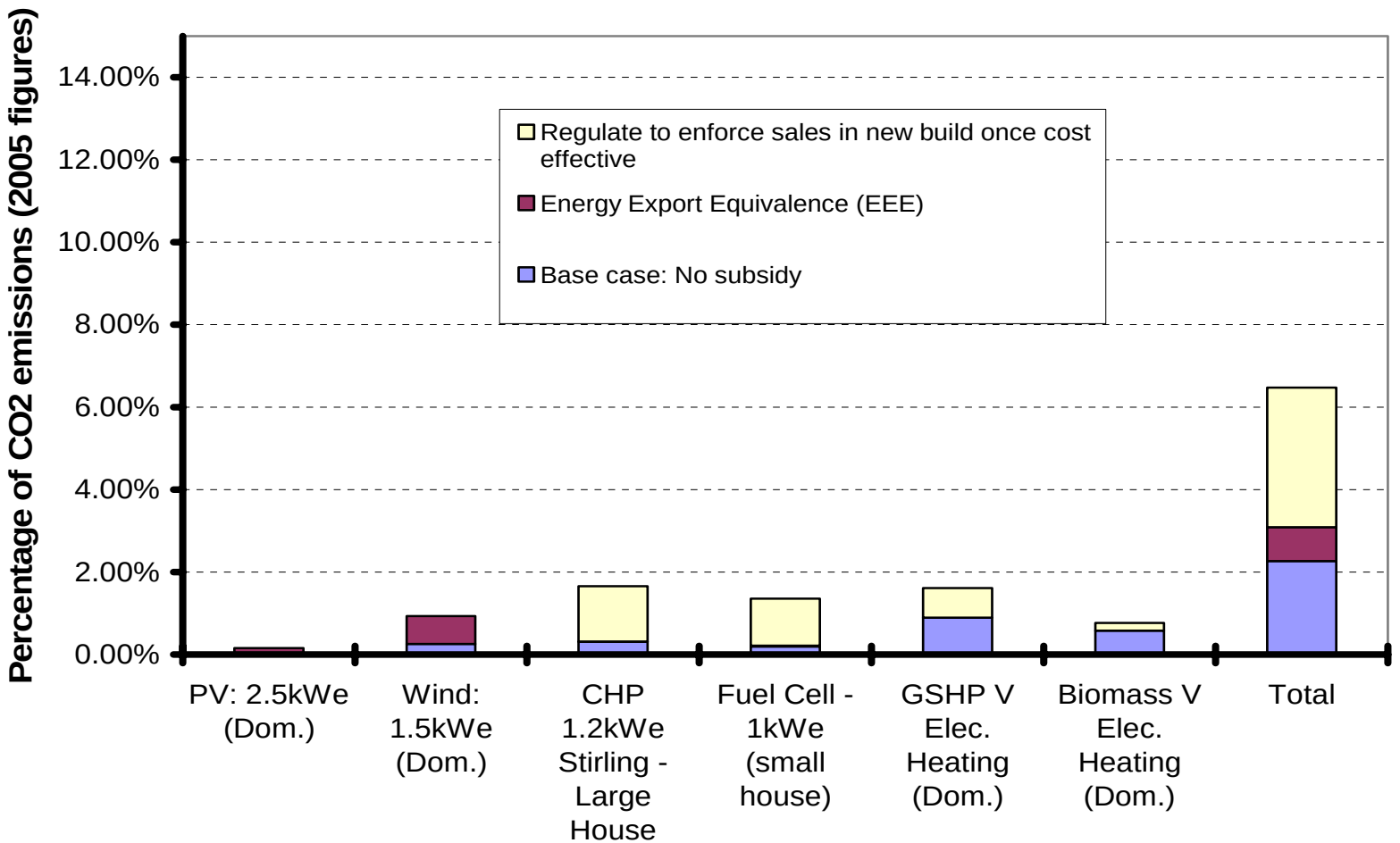
- The cost of energy from above is used to predict the market growth in the UK.
- This is achieved by comparing the generated energy cost with the relevant baseline costs (e.g. grid electricity for PV).
- Technology-dependent market growth conditions are applied including factors such as maximum growth capability and total market size.
- This allows the installed capacity (in terms of capacity, CO_2 savings or investment) to be evaluated for the period 2005 -2050.

Market support

- The above costs are based on un-supported technologies in a commercial environment.
- The model allows for additional market support to be modelled. This includes mechanisms such as capital support, soft loans, Renewable Obligation Certificates (ROCs), regulation and metering options.

Timely regulation of cost-effective technology will be important to achieving significant CO_2 reductions by 2030.

Percentage of CO2 emissions saved due to microgeneration in 2030: (based on 2005 CO2 emissions in the domestic sector).



(*) Based on 198 MT CO_2 p.a. arising from the domestic sector (UK Energy Sector indicators 2005, DTI).

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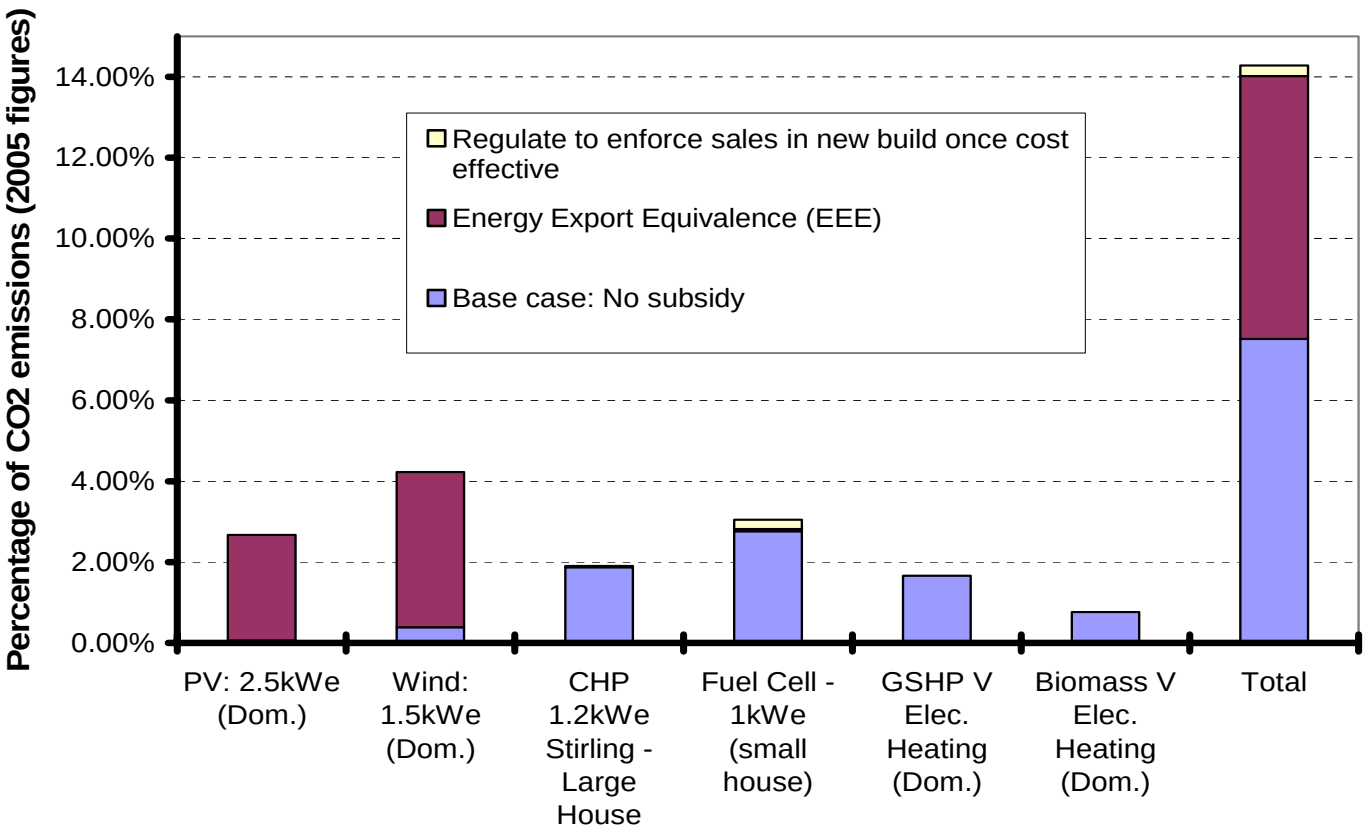
A fair value on exported electricity is vital to achieving significant CO_2 savings by 2050.

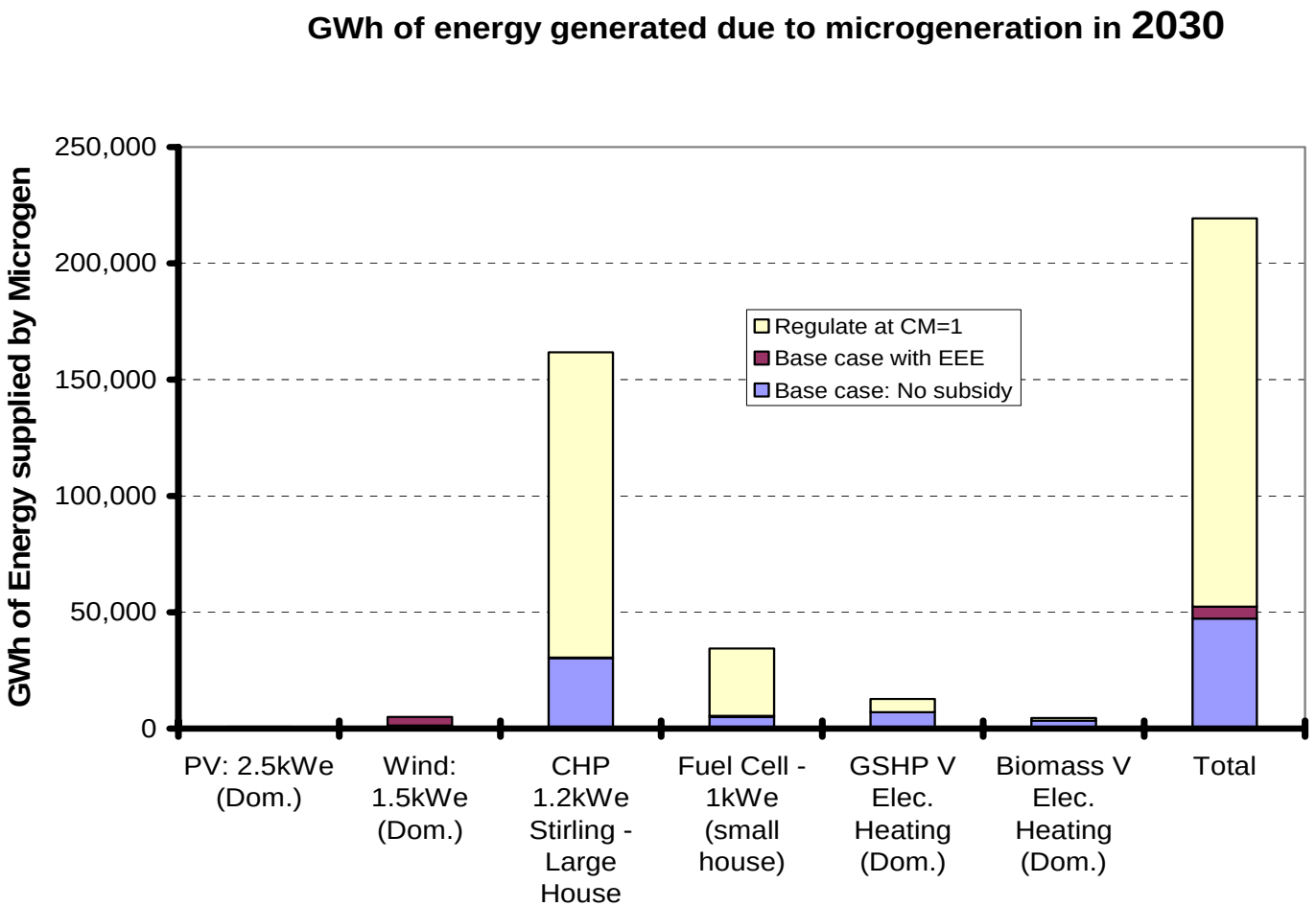
Percentage of CO2 emissions saved due to microgeneration in 2050: (based on 2005 CO2 emissions in the domestic sector).



- Larger fuel cells could make an even more significant contribution, but this could have more implications for the operation of energy markets and the grid.

- Data here is based on 198 MT CO_2 p.a. arising from the domestic sector (UK Energy Sector indicators 2005, DTI).
- Domestic sector CO_2 emissions are approx. 30% of UK emissions (including transport).
- Note: If using 150MT CO_2 p.a., the total 2050 domestic sector CO_2 saving rises to 18%. (This figure used in “Options for a Low carbon Future” AEA 2002.

Timely regulation of cost-effective technologies will be important to achieve significant microgeneration capacities by 2030.

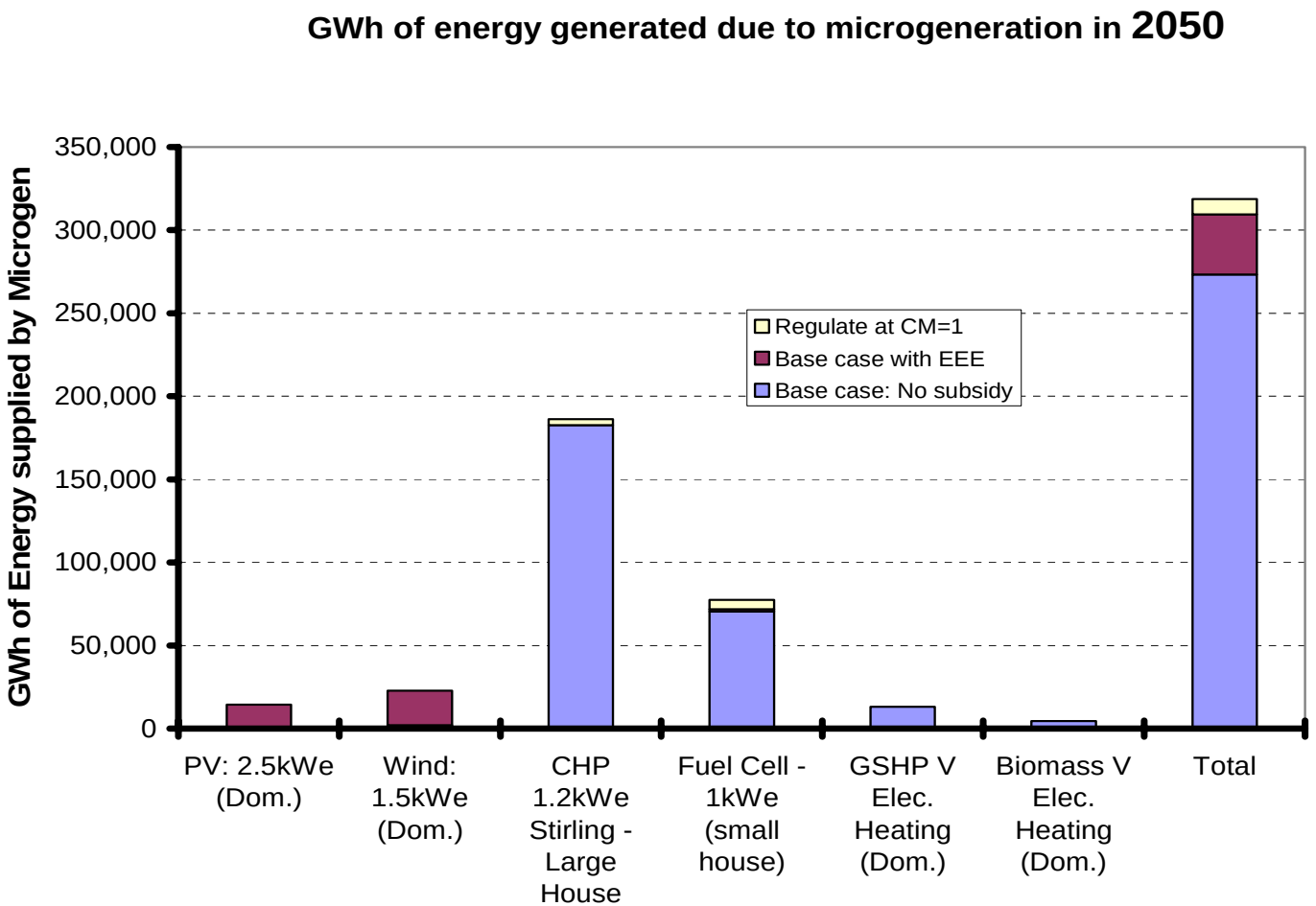


- Data in the graph is for total output, including heat and electricity.
- Electricity demand in UK is circa 380 TWh/annum, or 380,000 GWh/annum (2000 figure). (Electricity only).

PV = Photovoltaics; CHP = Domestic Combined Heat and Power; GSHP = Ground Source Heat Pump.

EEE = Energy Export Equivalence (energy exported to the grid is given a value equivalent to the cost of imported energy).

By 2050, fairer valuation for exported electricity is vital for assisting renewable microgenerators.



- Data in the graph is for total output, including heat and electricity.
- Electricity demand in UK is circa 380 TWh/annum, or 380,000 GWh/annum (2000 figure). (electricity only).
- Summing all microgen. electricity outputs in 2050 gives circa 100TWh/annum (approx 25% of UK 2005 Electricity demand).
- This capacity could be reached sooner subject to improved regulation and support.

Stirling engine CHP: this could be a major contributor to UK domestic energy requirements.

Current status and potential

- Currently, the technology is not far from being cost effective. This is strongly dependent on achieving lifetime and maintenance costs close to those of the incumbent (gas boilers).
- Following likely commercial introduction circa 2010, this sector grows quickly as costs reduce further.
- After cost effectiveness is achieved, as installations grow from very low (current) levels, it could take another 10-15 years before a significant proportion of domestic energy is generated by this technology.
- This technology is likely to be successful in larger dwellings with higher than average heat loads. Over 8 Million homes could be reached by 2050, supplying 40% of domestic heating requirements and 6% of UK electricity supplies.

Support required

- Mass market uptake could be accelerated through energy supplier programmes and then by a requirement for use within the Building Regulations.
- Such regulation need only occur when the technology is cost effective for the consumer, and therefore would be consistent with the current approach in Building Regulations, for example to the requirement for use of 86% efficient boilers at current costs.

Fuel cell CHP: once commercialisation is achieved, this could be the dominant microgen electricity generator.

Current status and potential

- This technology is more suited to smaller dwellings with lower than average heating loads. Any future reductions in domestic heating loads (through higher standards for building fabric) would increase the market for this technology.
- Commercialisation is strongly dependent on achieving lifetime and maintenance costs close to those of the incumbent (gas boilers).
- Cost effective introduction is likely circa 2015. Thereafter costs continue to reduce significantly.
- In 2050, with appropriate support, small fuel cells could supply 9% of UK electricity requirements and reduce domestic sector CO_2 by 3%.

Support required

- As with Stirling engines, mass market uptake could be accelerated through energy supplier programmes and then by a requirement for use within the Building Regulations.
- Such regulation need only occur when the technology is cost effective, and therefore would be consistent with the current approach in Building Regulations, for example to the requirement for use of 86% efficient boilers at current costs.
- An alternative (3kWe) fuel cell has also been modelled. This technology is heat led and oversized relative to domestic electricity demand and so exports a significant fraction of its electrical output. This technology is highly dependent on achieving a more equitable value for exported electricity (EEE). Without this, this technology could produce 1.6% of UK annual electricity demand, but with EEE, this could rise to 18%.

Small Wind: commercialisation could be achieved near term, with a significant contribution to CO_2 reduction.

Current status and potential

- Small wind systems are generally not cost effective at present.
- However, a number of new products have recently come to market with potential for significant volume related cost reductions. As a result, mass-commercialisation could occur circa 2015.
- The potential for small wind is significant – there are a number of UK developers, a suitable UK market of significant size and near term potential for significant cost reductions.
- With appropriate support, small wind could supply 4% of UK electricity requirement and reduce domestic CO_2 emissions by 6%.

Support required

- In the short term, this technology will need to be supported through the period of time until commercialisation is achieved (2015). Projections suggest a capital grant of circa 25-50% could be sufficient to support uptake levels until this time.
- However, commercial viability is highly dependent on acquiring a more equitable price for exported electricity (EEE). This would be the single most important market change for small wind.
- Poorly informed planning decisions could increase costs and reduce the market quite significantly. An objective assessment of the environmental impact of domestic small wind systems is required to provide clarity on this issue, followed by guidance to planners on the key issues including permitted development status.

Photovoltaics: a technology with significant potential, but cost of energy is likely to remain high for some time.

Current status and potential

- Photovoltaics are not generally cost effective at present. In many countries (including the UK) significant incentives are required to maintain the market for small grid connected systems.
- There are small markets where PV is already cost effective, including for remote power and in prestige facades.
- Cost effectiveness is not predicted to occur until 2030. However, a technology breakthrough could reduce capital costs and bring this forward towards 2020.
- Lack of planning issues means the market potential for PV is amongst the largest of those studied.
- If cost issues were overcome, this technology could supply almost 4% of UK electricity demands, and reduce domestic sector CO_2 emissions by up to 3%.

Support required

- Significant incentives will be required to maintain the market until commercialisation is reached in circa 2030.
- Thereafter a more equitable value on exported energy (correcting a current price distortion) will be required to ensure commercial viability.

Biomass heating and heat pumps: renewable heating has significant potential for CO_2 reduction.

Current status and potential

- Both biomass heating and GSHP technologies can be commercial when compared against electric or LPG heating. In general the technologies are not competitive with natural gas or oil fired heating.
- Although only a small proportion of the housing market uses electric heating, and only a fraction of these will be suited to biomass or GSHP, the CO_2 savings are disproportionately large (due to the high CO_2 emissions of electric/LPG heating).
- With appropriate support, these technologies could reduce domestic sector CO_2 emissions by 3%.
- These applications would also be likely to contribute disproportionately to alleviation of fuel poverty in low income households living in the hard-to-treat homes off the gas grid.

Support required

- These microgeneration technologies both rely on wet-heating systems to be installed instead of electric and LPG. This could be a significant barrier due to the perceived simplicity of electric heating systems in particular.
- Regulation could therefore be used to improve uptake in preference to electric or LPG in appropriate regions (especially off the natural gas grid). For example incentivisation in the Building Regulations or in local/national planning guidelines.
- For low income households it may be appropriate to use direct grant support through Warm Front and its devolved counterparts.

Solar water heating: limited cost reduction potential results in low growth.

Current status and potential

- Currently the largest microgeneration industry, installing 2000 units annually.
- Generally, solar water heating is not cost effective at present.
- The technology is most effective if replacing electric heating systems.
- However, while capital costs are projected to reduce, the learning rate appears low and it is not likely that solar water heating will provide cost effective water heating over the timescales of the study without substantial grant support.

Support required

- Significant grant funding (on the order of 50% of capital costs) would need to be maintained long term to support the market.
- Lower levels of grant funding, or access to EEC would assist but installation levels would be significantly lower than potential.

Projections of cost suggest that numerous microgeneration technologies will produce cost competitive energy by 2020.

Current status

- Few microgeneration technologies are cost effective at present.
- Notable exceptions are biomass heating and ground source heat pumps which could be cost effective when compared with electric heating systems. Small commercial scale (sub 50kW) CHP units are borderline cost effective at present without a technology breakthrough.
- The rate at which cost competitive technologies enter the market will depend on some key factors:
  - -the speed at which industry can scale up production and installation capacity and skills;
  - -awareness in, and the size of, the early adopter market;
  - -the extent, type, and effectiveness of policy interventions to develop early niche markets.

  There are significant uncertainties in these factors. The contribution that microgeneration can play in the medium term (e.g. in 2020) in the energy supply and carbon emissions reduction therefore needs more detailed examination.

Potential

- A number of microgeneration technologies have the potential to become part of a commercial, mass market decentralised energy system for the UK, supplying a large fraction of UK electricity and heating requirements at a cost competitive with today's supply. In the process substantial quantities of CO_2 emissions would be avoided.
- There is a wide spread in projected dates when cost competitive energy is produced by microgeneration technologies: Stirling engines are earliest (2010-2015), with small wind and fuel cell CHP following circa 2015-2020. Domestic photovoltaics are unlikely to produce equivalent cost energy before 2030.

A model of the likely uptake of each technology has been established, >15% domestic CO_2 reductions possible.

The table below summarises results for CO_2 emissions avoided (expressed as a percentage of UK domestic CO_2 emissions*) for different microgeneration technologies in the uptake model under different government intervention schemes (these results are not necessarily additive).

	PV: 2.5kWe (Dom.)	Wind: 1.5kWe (Dom.)	Biomass V Elec. Heating (Dom.)	GSHP V Elec. Heating (Dom.)	Active Solar V. Elec Heating (Dom.)	CHP 1.2kWe Stirling - Large House	Fuel Cell - 1kWe (small house)	FC: 3kW (large house)
2030								
No subsidy	0.0%	0.3%	0.6%	0.9%	0.0%	0.3%	0.2%	0.1%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	0.2%	0.9%	0.6%	0.9%	0.0%	0.3%	0.2%	0.2%
Capital subsidy of 25%, whilst costs reduce	0.1%	0.9%	0.6%	0.9%	0.1%	0.3%	0.2%	0.1%
Regulation to introduce tech. in all new build once cost effective	0.0%	0.3%	0.8%	1.6%	0.0%	1.7%	1.3%	0.1%
2050								
No subsidy	0.1%	0.4%	0.8%	1.7%	0.0%	1.9%	2.8%	0.4%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	2.7%	4.2%	0.8%	1.7%	0.0%	1.9%	2.8%	5.5%
Capital subsidy of 25%, whilst costs reduce	0.2%	4.2%	0.8%	1.7%	0.1%	1.9%	2.8%	1.3%
Regulation to introduce tech. in all new build once cost effective	0.1%	0.4%	0.8%	1.7%	0.0%	1.9%	3.0%	0.4%

(*) Based on 198 MT CO2 p.a. arising from the domestic sector (UK Energy Sector indicators 2005, DTI).

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A substantial percentage of UK electricity demands could be supplied by microgenerators.

The table below summarises results for microgeneration electricity production (expressed as a percentage of UK electricity demands*) for different microgeneration technologies in the uptake model under different government intervention schemes (these results are not necessarily additive).

Percentage of total UK electrical energy demand.	PV: 2.5kWe (Dom.)	Wind: 1.5kWe (Dom.)	CHP 1.2kWe Stirling - Large House	Fuel Cell - 1kWe (small house)	FC: 3kW (large house)
2030					
No subsidy	0.1%	0.4%	1.0%	0.7%	0.3%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	0.2%	1.3%	1.0%	0.7%	0.6%
Capital subsidy of 25%, whilst costs reduce	0.1%	1.2%	1.0%	0.7%	0.5%
Regulation to introduce tech. in all new build once cost effective	0.1%	0.4%	5.5%	4.5%	0.3%
2050					
No subsidy	0.1%	0.6%	6.3%	9.3%	1.3%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	3.8%	6.0%	6.3%	9.4%	18.4%
Capital subsidy of 25%, whilst costs reduce	0.3%	5.9%	6.3%	9.3%	4.4%
Regulation to introduce tech. in all new build once cost effective	0.1%	0.6%	6.4%	10.0%	1.3%

(*) Based on 380 TWh of electricity p.a. required in the UK (2005).

Summary of network issues.

Network issues

- Voltage rise is the first network issue encountered in the model as micro-generation penetration levels increase.
- Followed by reverse power flow.
- Voltage unbalance is unlikely to cause a problem.
- Fault level constraints were not encountered in the model.
- Following reverse power flow, thermal constraints may be encountered.
- ALL NETWORK ISSUES ARE LOCATION SPECIFIC i.e. the microgeneration level which triggers the need for mitigation measures will be location specific, as will the cost and nature of the mitigation method.

Mitigation

- Any network issue can be resolved.
- This is a matter of economic rather than technical limitations.
- Extrapolation to the GB system is very difficult, ranging from £150m-£240m to mitigate voltage rise, £60m-£650m to mitigate reverse power flow, and £2.5bn (DNO estimate) to mitigate all network issues.
- Alternative mitigation methods, other than the traditional reinforcement, are possible.

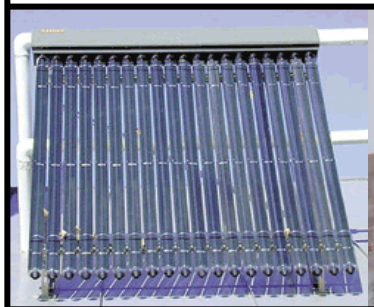
Contents

A wide range of microgeneration technologies are currently being deployed in the UK, representing a nascent industry.

Electricity

Photovoltaic
Wind
Hydro





Heat

Solar water heating
Biomass
Ground source heat pump

Combined Heat and Power

Fuel Cell
Reciprocating engine
Stirling engine

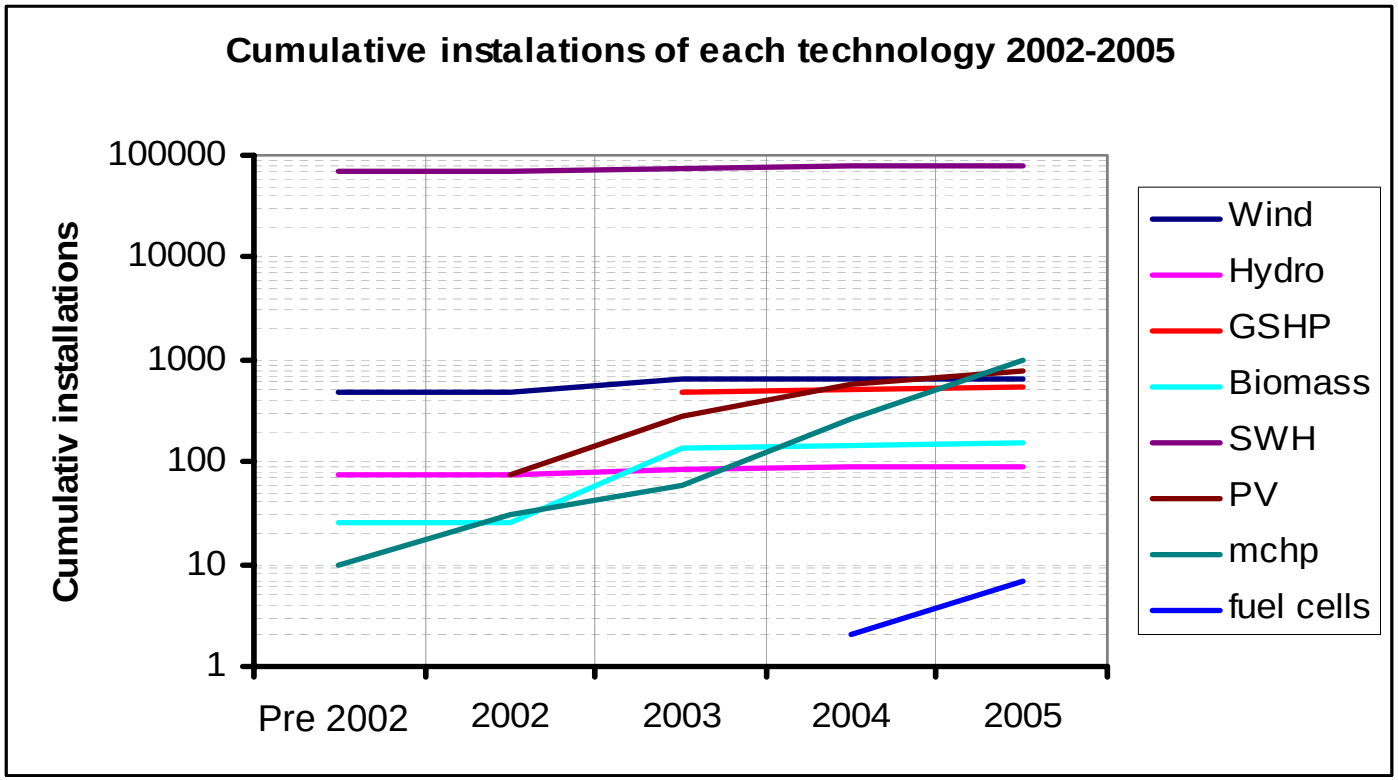

There are currently fewer than 100,000 microgeneration installations of all types across the UK. The majority are solar water heating installed before 2000.

Technology	Total Number of installations in the UK	Estimated total cost of installations
Wind	650	£11,137,463
Hydro	90	£2,385,084
Ground source heat pumps (GSHP)	546	£5,156,751
Biomass boilers (pellets)	150	£1,165,709
Solar water heating	78,470	£357,696,065
PV	1,301	£20,145,012
Micro CHP	990*	Not known
Fuel cells	5	Not known
TOTAL	82,202	£397,686,084

- The existing installed base is heavily dominated by solar water heaters.
- Other technologies (notably wind, PV and GSHP) have emerged, assisted by grant programs and technical development.
- Total no. of installations taken from best known sources (previous estimates and known installations funded by government programmes).
- Total costs are based on average unit costs taken from known sources.

*taken from industry survey data

Over the past 5 years installations of microgeneration have increased due to grant programs and cost reductions.



- Solar water heating remains the largest market but growth is modest.
- Solar PV installations have seen the sharpest growth since the programmes were launched along with notable increases in biomass and wind installations from 2003.
- Ground source heat pumps have grown from a very low base at the start of the support programmes (NB very few installations before clearskies).
- Mchp installations have also grown rapidly without grant support from government.

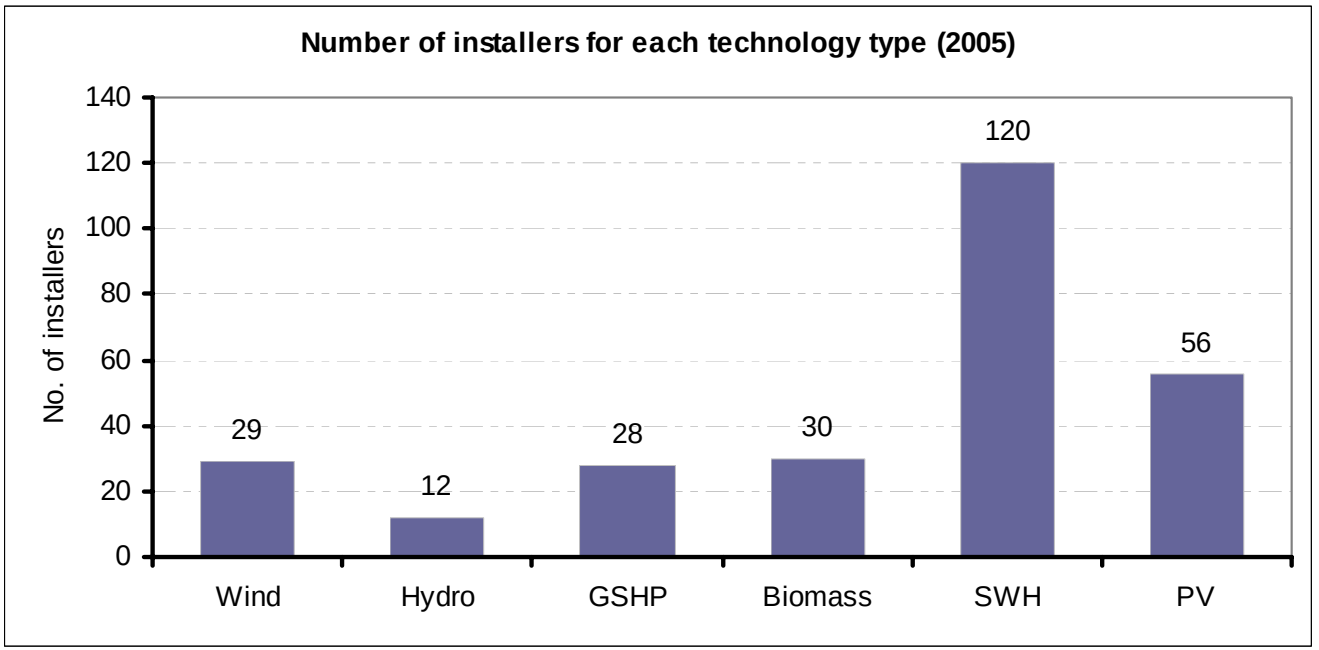
Household renewables installations funded by Government programmes since 2002.

The table below lists domestic microgeneration renewables installations funded by Government programmes since 2002

Technology	Number of installations	Number of Installers	Total Installation Costs	Estimated annual turnover
Wind	165	29	£2,775,798	£925,266
Hydro	12	12	£344,512	£114,837
GSHP	500	28	£4,845,079	£1,615,026
Biomass	116	30	£777,139	£259,046
SWH	6,694	120	£24,660,834	£8,220,278
PV	1,301	56	£20,145,012	£6,715,004
TOTAL	**8,788**	**275**	**£51,101,864**	**£17,033,955**

- The market is dominated by Solar installations. This is mainly due to the mature nature of the SWH technologies and the generous support programmes which solar PV technologies have received since 2002.
- Heat pump installations have increased significantly since the launch of the DTI clearskies programme. The micro-wind sector is rapidly emerging since the development of cost-effective turbines in the last 2-3 years.
- The number of installers has increased significantly since the launch of the DTI support programmes.
- Estimated annual turnover is approximated at ~£17M excluding mchp and fuel cells sectors with fewer companies and more emphasis on technology development.

The number of installers currently available for each technology is proportional to the annual installations.



Predominant Installer

- There are over 275 installers operating in the microgeneration sector, with an estimated average annual turnover of £62K per co. since 2002.
- The majority of installers operate within in the solar industry – 64%.
- Remaining technologies have a significant number of installers operating in the relevant sectors which may not reflect the proportionate number of installations. This is due to companies covering both the residential and commercial sectors and also companies for whom the microgeneration activity is not their primary business.
- In the micro CHP sector activity is concentrated in a small number of companies

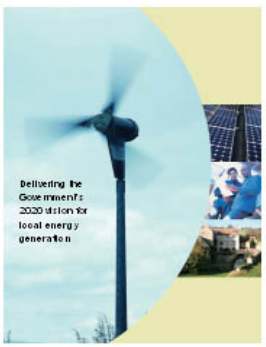
Overview of UK microgeneration industry.

- The household microgeneration sector is still relatively small with less than 100,000 installations in total to date in the UK. The majority of these installations was derived from early solar hot water heating installations.
- There has been significant growth in some sectors since the launch of government support programmes.
  - Particularly in solar PV and GSHP.
- Estimated annual turnover for all technologies supported by government programmes is between £10m and £20m.
  - The solar PV sector returns the highest turnover rates with proportionally higher turnover per installer due to high cost of the technology and relatively large no. of installations.
- The numbers of organisations operating in this industry has also grown significantly in tandem with the support programmes.
  - E.g. PV installers growing from a baseline of 15 co.s to over 50 co.s in 3 years.
  - The mchp and fuel cell sectors are very different to other sectors with very few companies employing the largest no. of staff, which is indicative of the investment being made in these technologies and likely early large scale adoption of the technologies.
  - Most companies employ between 0-30 staff, with very few employing >100 staff (notably in the mchp sector).
- It is estimated that there are between 200 & 600 jobs in the microgeneration sector based on estimated turnover, excluding mchp and fuel cells.
- Fuel cell and microCHP jobs are primarily in research and development, whilst the technology is commercialised.

Contents

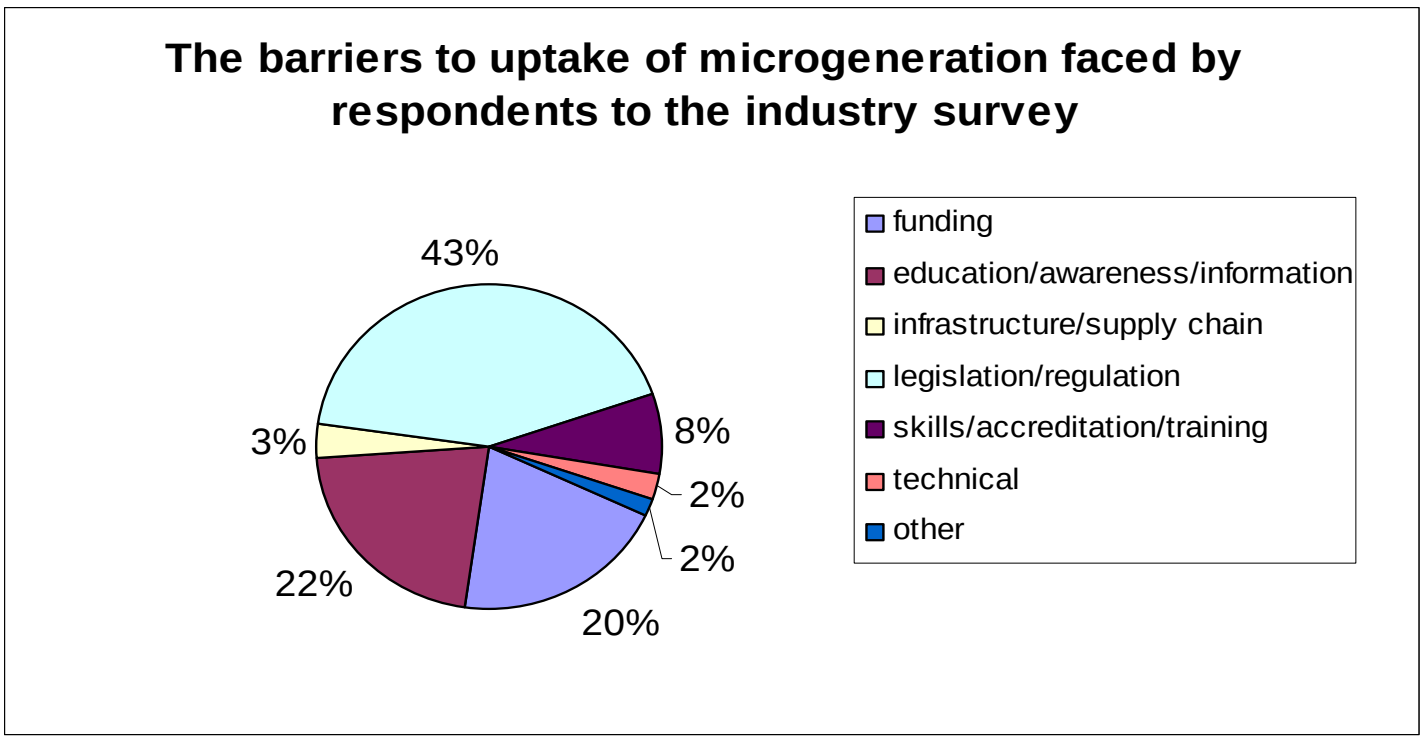
The industry view on barriers and opportunities for microgeneration have been assessed through consultation.

- The following analysis of barriers and opportunities for microgeneration technologies in the UK is derived from an industry survey, a set of industry round table sessions, a literature search and EST's knowledge of the industry.
- EST conducted an email survey on the microgeneration market which was sent to 395 industry stakeholders. 17% responded.
- EST published a document to stimulate the debate on the future of UK mass market microgeneration. In parallel, EST facilitated a series of round table sessions to discuss the cost, information and technical constraints and the mass market transformation initiatives required to increase customer demand and capacity in the supply chain. Over 30 industry stakeholders attended at least one of the sessions.
- The industry survey and round table sessions provided good quality feedback covering these softer issues.
- The round table sessions generally provided a better understanding of key concerns and how they might be addressed.



Breakdown of the barriers from the survey suggests cost and regulations are seen as the major barriers to increased uptake.

- 61% of respondents identified the high cost of the technology as the most important barrier to overcome. The majority of these were from the PV sector.
- When asked to identify additional barriers, 80 % went on to provide examples. In total, industry identified 124 additional barriers with heavy duplication.



- 43% identified legislation and regulation constraints as the next major barrier to uptake of microgeneration after high cost. These are generally disincentives rather than absolute constraints.

Cost is identified as a major constraint, which requires short term action to stimulate the market.

Barrier	Importance	Industry suggestions for mitigation actions	Timescales
High cost of technology Microgeneration technologies are currently produced in small numbers with limited automation.	HIGH	• Provide future government capital grant support to increase the number of installations so industry can reduce the cost. Grants are vital in the early stages for the market. Build on success of the existing grant programmes.	Short term
		• Ambitious long term commitment to microgeneration targets would attract investment to scale up production and drive down costs.	Medium to long term
		•Mandate that a certain proportion of applicable buildings energy needs are met by microgeneration under the Code for Sustainable Building. The Code should anticipate the next round of the Buildings Regulations.	Short term
		•Mandate the inclusion of microgeneration in the next update of Part L of the Building Regulations in 2010.	Medium to long term

Installed cost could be reduced by easing planning restrictions and by improving the fiscal regime.

Barrier	Importance	Industry suggestions for mitigation actions	Timescales
Planning permission Many microgeneration technologies require planning permission from the Local Authority as they do not have permitted development status.	MEDIUM	Include relevant microgeneration technologies within Schedule 2 of the Town and Country Planning (General Permitted Development) Order 1995, and its Scottish equivalent.	Medium Term
Fiscal Failure to exploit opportunities for imaginative policy initiatives for microgeneration.	MEDIUM	Chancellor to develop a fiscal strategy to address current fiscal barriers and identify new mean within the tax system to encourage the uptake of microgeneration. These could be measures such as biomass boilers to benefit from the 5% VAT rate levied on household energy supply.	Medium Term

Low levels of consumer awareness and engagement can be solved through active education programmes and accreditation programs.

Barrier	Importance	Industry suggestions for mitigation actions	Timescales
Inadequate information The inadequate provision and co-ordination of impartial and locally relevant information and advice to customers.	HIGH	• Provision of information and advice to millions of customers. Strong communication campaign. • Practical support for appropriate organisations involved in sustainable energy delivery. •Cohesive regional and local framework delivery. •Provision of a consistent message through the supply chain and public agencies. •Delivery through a one stop shop advice service.	Short to medium term
Consumers negative perceptions of products and installers services Consumers are waiting for the products to be proven and for the installers to be experienced.	HIGH	• Develop robust accreditation standards against which individual microgeneration technologies can be type approved. • Develop product and installation standards for each microgeneration technology. Develop codes of practice for suppliers/sellers. • Establish a independent body to administer an accreditation scheme and to establish the codes of practice and product/installation standards.	Short term

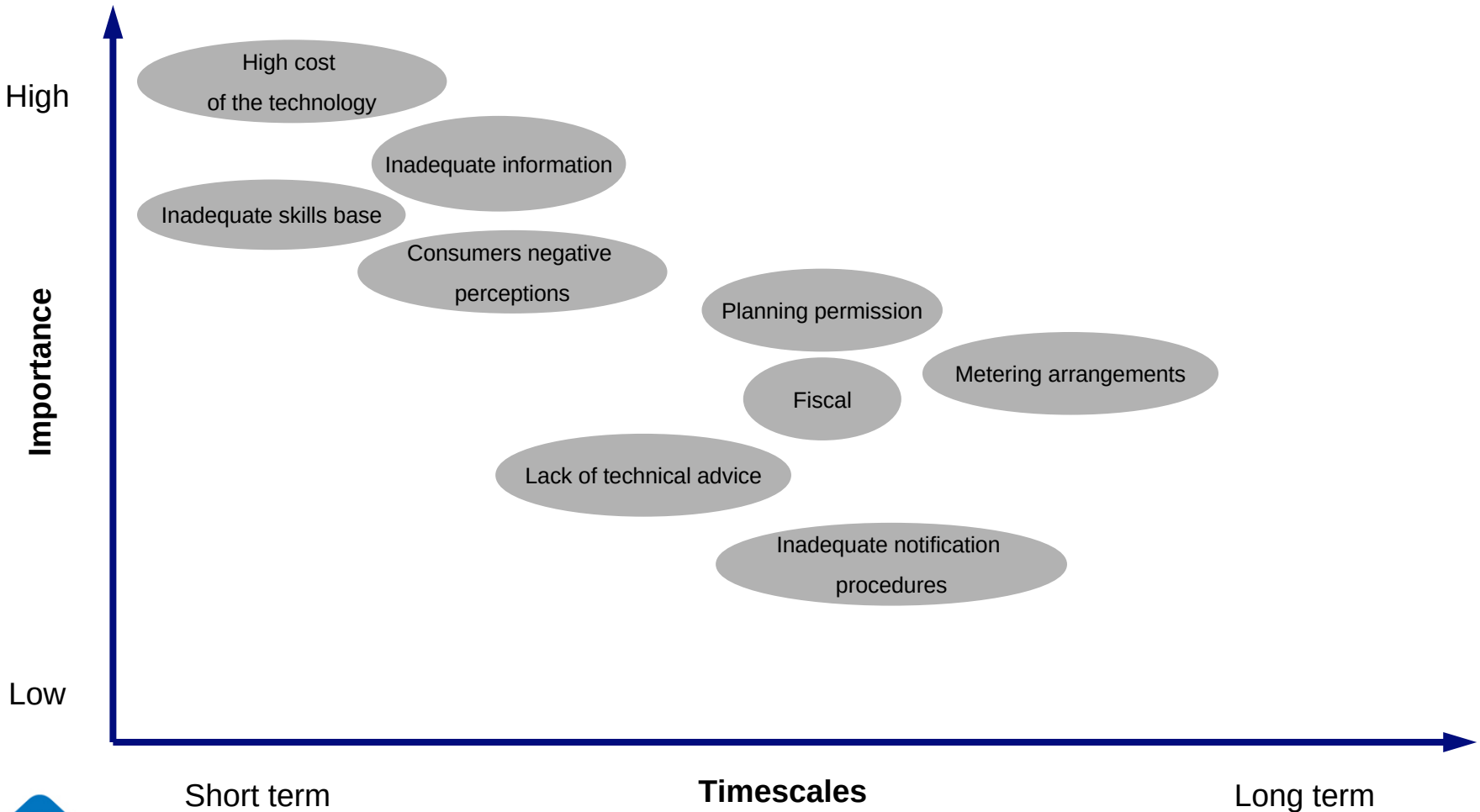
Mechanisms for metering and valuing exported electricity and renewable heat need to be resolved in the short to medium term.

Barrier	Importance	Industry suggestions for mitigation actions	Timescales
Metering and reward arrangements for electricity •Currently, the amount of electricity exported back onto the distribution network has a minimal impact on the overall balancing and settlement arrangements of the wholesale electricity markets. This is due to low penetration, but the numbers will increase. The metering arrangements for collecting and monitoring the data for the import, export and generation of electricity have still to be decided. •Customers find it difficult to be rewarded for their exported power from electricity suppliers. •The transaction costs for accessing ROCs and LECs exceed the level of benefit.	MEDIUM	There are a number of options: •'Net' metering could be permitted as an interim measure from 2006 to 2012 to allow the market to become mature. • Require all replacement meters to import/export. Introduced as a requirement within Schedule 7 of the Electricity Act. •Electricity suppliers could be obliged to offer and publish terms for purchasing exported electricity from households. •Type approved technologies could be awarded a deemed output at a fixed annual level of kWh dependant on the technology and installation site. The deemed contribution would be subtracted from the customer's actual gross consumption. •Allowing microgenerators to claim ROCs, LECs and REGOs by a predetermined entitlement rather than on the basis of metered output.	Medium Medium term Short to Medium term Short to Medium term Short to Medium term
Renewable heat There is currently no incentive for the generation of renewable heat	MEDIUM	Develop an incentive scheme to support use of renewable fuels for heating.	Short to medium

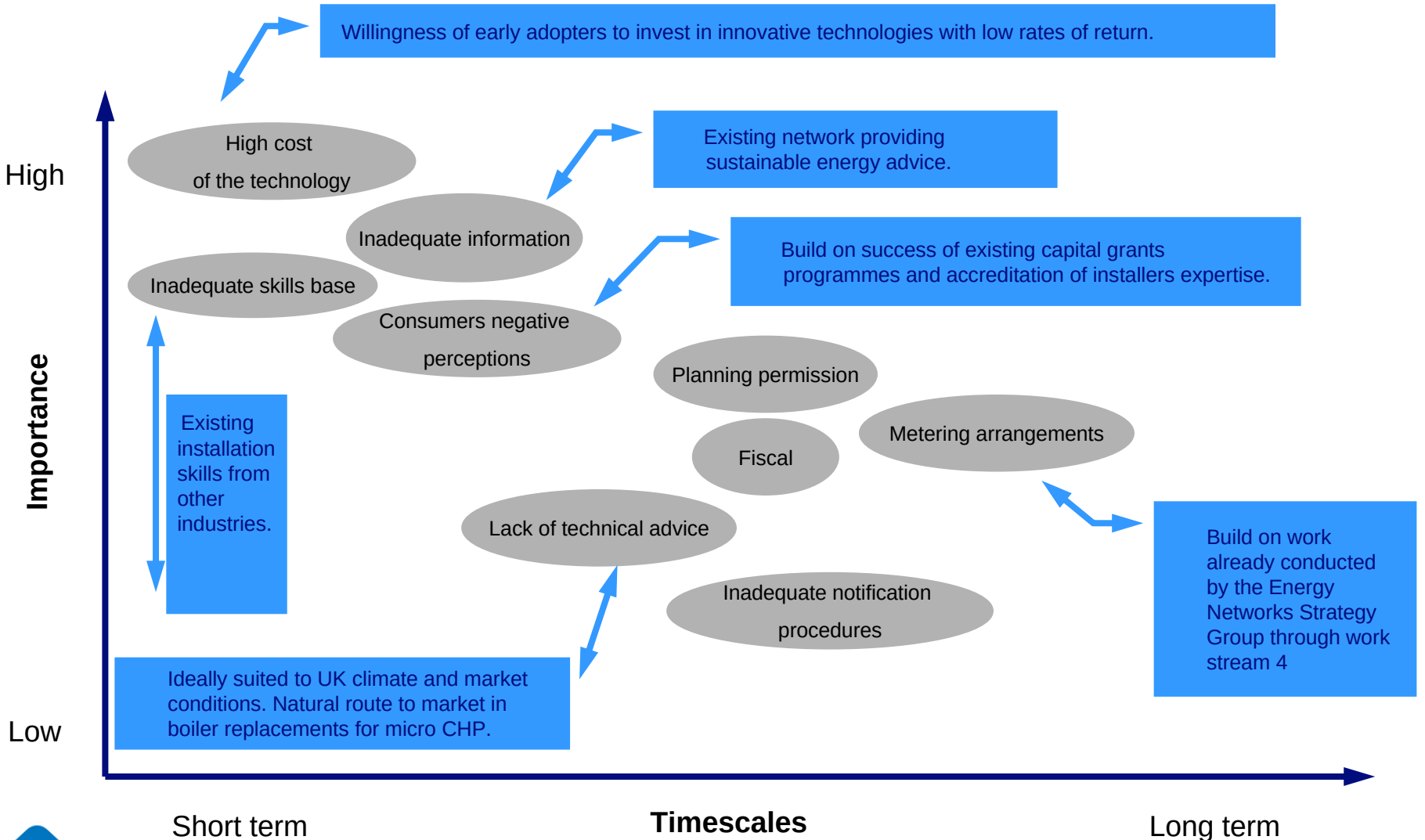
Improving the technical knowledge base of installers and end users is also seen as key to allowing increased uptake.

Barrier	Importance	Industry suggestions for mitigation actions	Timescales
Inadequate notification procedures Electricity suppliers have no direct knowledge of when customers have installed microgenerators.	MEDIUM/LOW	• Oblige Distribution Network Operator to notify the electricity supplier when a microgenerator has been connected to its network from a customer's premise.	Medium term
Lack of technical guidance for microgenerators The rules for distribution generation are daunting and guidance is needed on technical, commercial and regulatory issues.	MEDIUM	• Simple guide to the practical requirements of microgeneration and accompanying helpline for non-technical audiences (such as householders and new industry players).	Medium term
Inadequate skills base Shortage of appropriate skills and training courses.	HIGH	• Develop approved skills and training courses for each of the microgeneration technologies with the relevant skills councils and trade bodies. Given the long lead times involved with developing and accrediting training courses, this action should be an urgent priority.	Short term

Barrier importance vs. mitigation action timescales.



Key areas of opportunity for UK supply position.



Contents

N.b. a detailed description of the technology cost projection model is provided in Appendix A1

Projections have been produced for microgeneration technology costs to 2050.

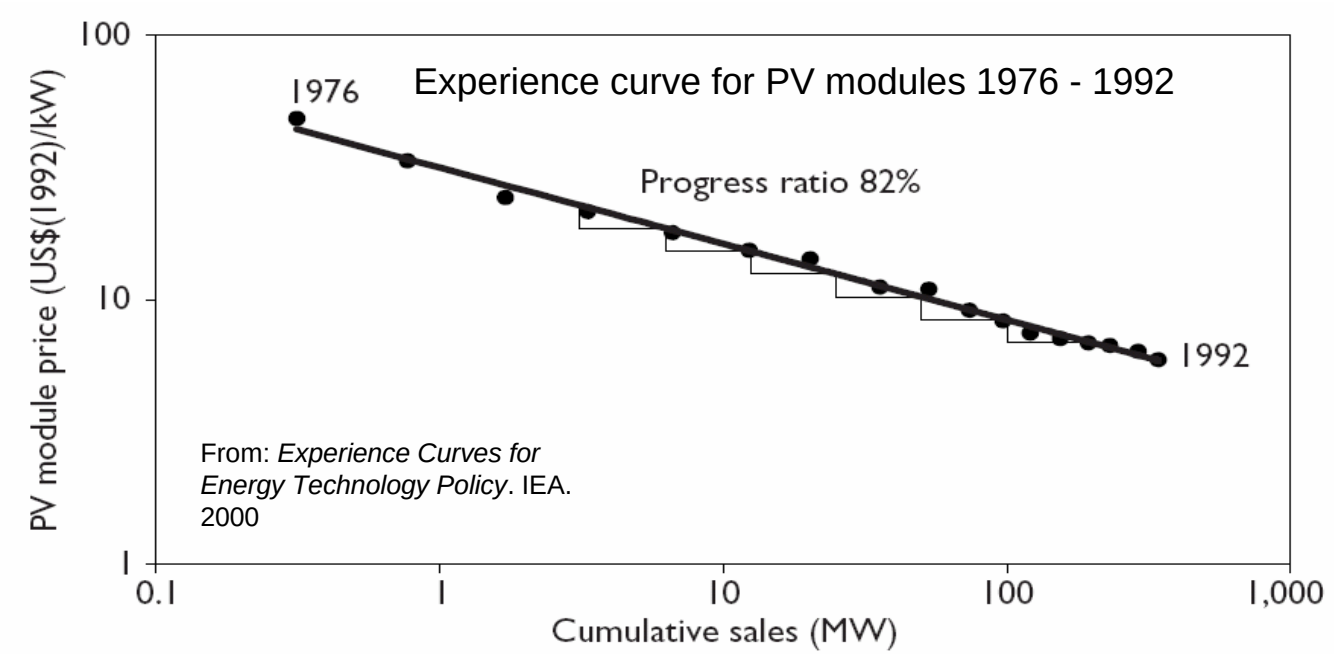
Global costs to 2050 are modelled using learning curve analysis:

- Historically, equipment capital (installed) costs have been observed to decrease over time as a function of cumulative production levels, giving a learning rate.
- These learning rates are used to predict future equipment costs over the period to 2050 for the purpose of this study. These can then be converted to provide effective energy costs to the consumer.
- These are predictions of “global” costs. For most technologies (e.g. photovoltaics), variation in uptake levels in the UK will not affect global technology price.
- Cost predictions are dependent on worldwide production meeting predicted levels.
- The result of this is that technology cost is exogenous to the UK uptake model which is presented later (section 3).
- Use of median, high and low predictions for technology cost allows representation of endogenous effects where these could be relevant e.g. for small wind or micro-CHP where the UK could lead worldwide introduction of the technology.

A detailed description of the technology cost modelling is provided in Appendix 1

Learning curves relate cost reduction to installed capacity.

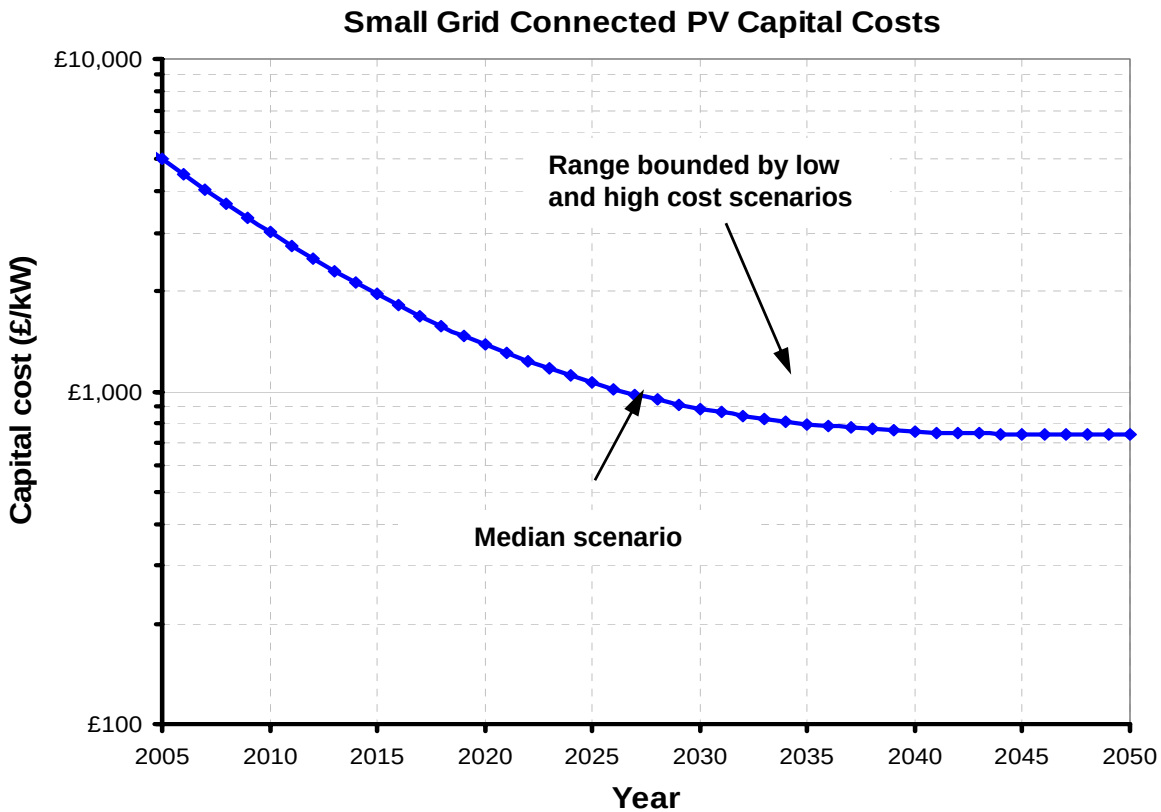
- Learning curves demonstrate a linear proportionality between *log(cost)* and *log(cumulative capacity)*.
- This indirect relation can include the effects of economies of scale, technological improvements, and other cost cutting measures.
- A doubling of cumulative volume (units, systems or installed capacity etc) provides a cost reduction expressed as a percentage – the learning rate*.
- For example, the PV learning rate was historically 18 %. Current estimates range between 18 % and 20 %:



(*) The learning rate can also be expressed as a progress rate. This is 1 minus the learning rate.

Upper and lower bounds from a ‘median projection’ are used to represent uncertainty in future costs – for example for PV…..

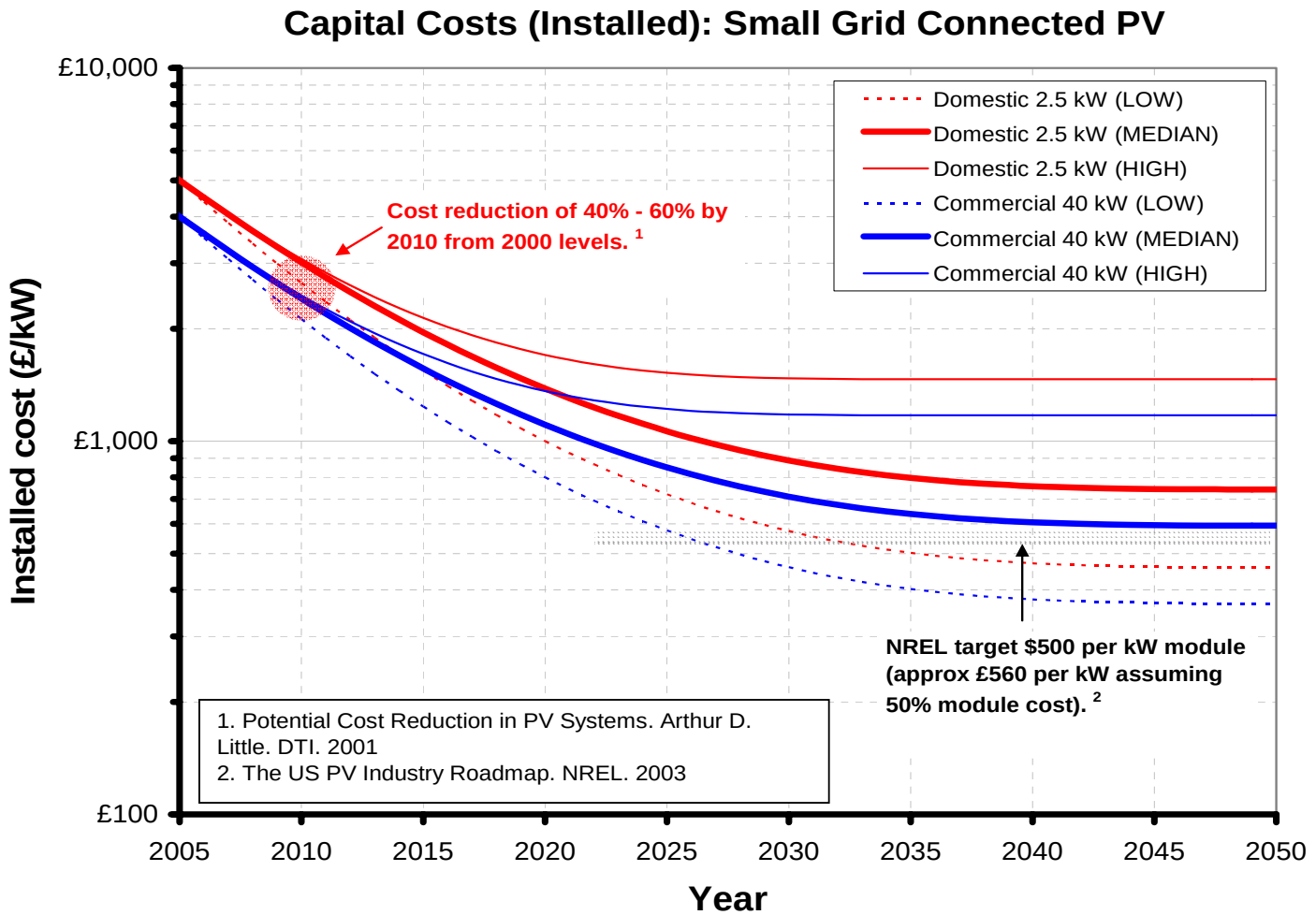
- Learning rates are used to calculate median unit cost from an assumed growth * profile for global installed capacity.
- Low and high cost scenarios are created by varying assumptions about the rate at which the market grows and the learning rate assumed for the technology.



(*) The growth profile is based on initial values and trends from published data wherever possible. For example, the data for PV were taken from IEA International Statistics. IEA Photovoltaic Power Systems Programme. http://www.iea-pvps.org/

Capital costs can be sense checked against the literature for each technology. This analysis is repeated for each tech. (Appendix A1).

- Projected costs in 2020 are in-line with detailed engineering analysis predictions.
- Costs start to stabilise circa 2020 – 2040 as the market reaches maturity.
- Final costs approach US targets for the median scenario.



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The capital costs are used to convert to an overall cost of energy produced by each microgeneration technology.

The cost of energy (£/kWh) from each microgeneration technology is calculated accounting for:

- Annualised capital cost.
- Maintenance cost (as a percentage of capital cost).
- Annual fuel cost (where relevant).
- Annual energy output (with typical UK specific performance characteristics where relevant).
- Interest rate of 8 %.
- Loan length made equal to lifetime (based on manufacturers warranty where available).

These values are then compared with baseline energy costs:

- Baseline costs are the offset energy cost, i.e. the value of replaced energy.
- The baseline cost for PV and wind for example is the grid electricity cost.
- Baseline for heating technologies is either natural gas and boiler installation, or electrical heating.
- For CHP technologies, a “hybrid” baseline energy cost is used. This is a weighted average of heat and electricity replaced.

Excess electricity exported to the grid is currently sold at an “export sale price”, this requires a model of electricity export.

- The **Export sale price** is currently approximately £0.025 / kWh*. Industrial electricity trends are used to project the export sale price to 2050.
- The **Export percentage** is the proportion of electricity exported to grid. This is set at a fixed percentage for each technology #:

Microgeneration technology	Percentage of electricity exported to grid #
PV	50 %
Wind	60 %
Hydro	50 %
CHP	33 % (72 %) **

- The **Effective baseline energy cost** is a ratio of the value of electricity used on site and the total export sale revenue for the electricity exported to the grid. For example, with 33 % export:

Effective base cost / kWh = 0.67 × (grid electricity price / kWh) + 0.33 × (export sale price / kWh)

- It is assumed that all heat is used on site, not exported, and therefore this issue of reward below the consumer market price is not relevant for heat.

(*) This is a weighted average of the Relevant Metered Output Price (RMOP) over each settlement period.
(#) Data taken from Metering, Settlement, and Export Reward – Options for Micro-generation. Ilex Energy Consulting. DTI. 2005.
(**) A 72 % export value is modelled for the generic 3 kWe/3 kWth fuel cell CHP system designed to operate as a de-centralised grid generator.

In addition the model considers the effect of valuing electricity export at the same value as the imported electricity value (EEE).

Because microgenerators supply energy close to the point of use on the electricity distribution system, they can claim to provide many of the services currently included in a typical electricity bill (avoided transmission and distribution losses, avoided transmission system charges, some avoided distribution system charges) as well as generation costs. As such it is often claimed that exported electricity from a microgenerator should be valued at the same rate that electricity is imported by a consumer. This Energy Export Equivalence is explicitly considered in the model.

Energy Export Equivalence (EEE) is modelled as:

- The export sale price is set equal to the purchase price of grid electricity*.
- The base energy price is therefore the grid electricity price appropriate to the operator.
- The effect of this is identical to 0 % export.

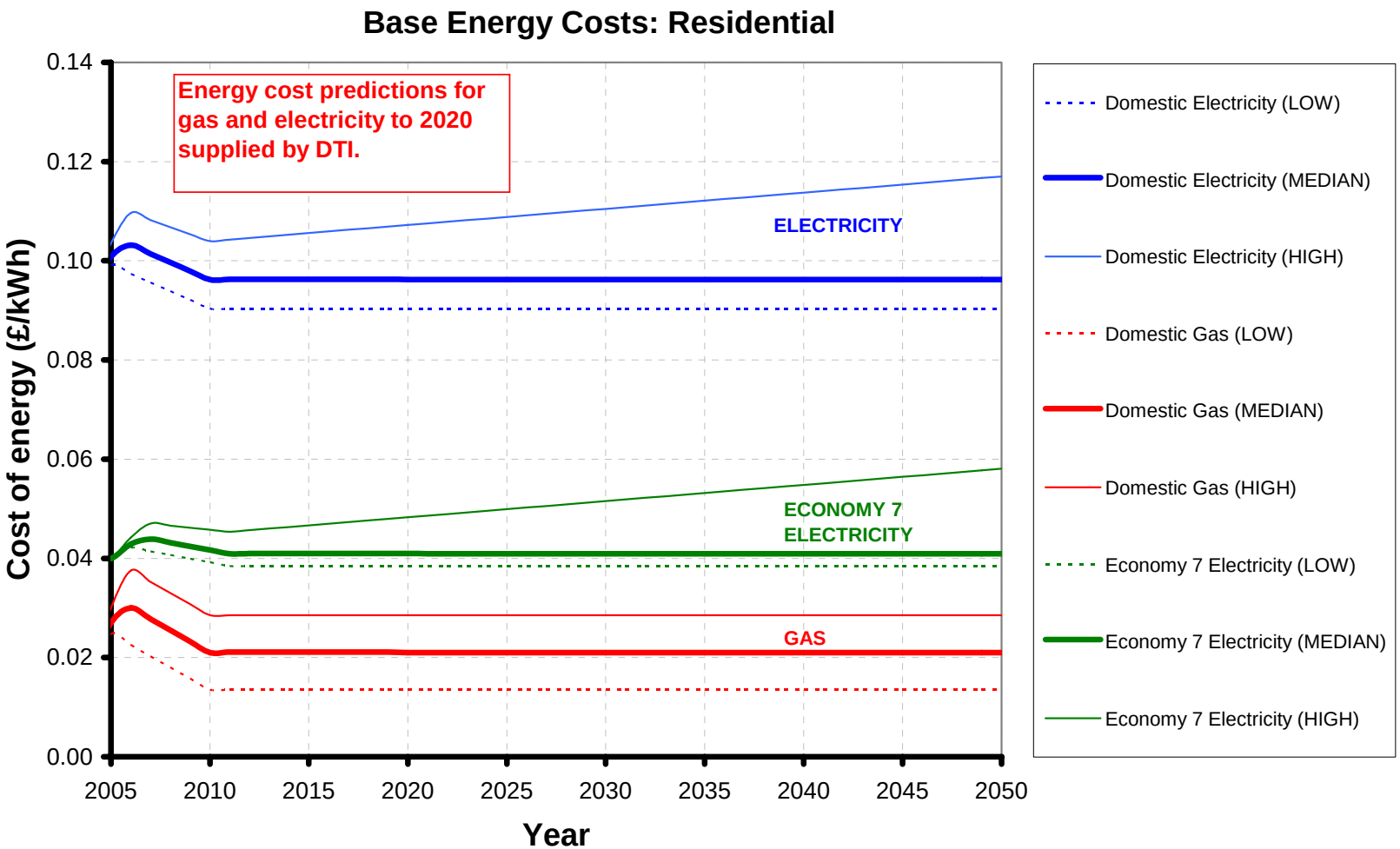
This can be compared with the base case (Non EEE) where:

- Excess electricity is exported to the grid and sold at a reduced price* similar to that of a large scale generator.
- The base cost is lowered to the effective base cost level.
- Non EEE reward increases the cost per kWh of electricity consumed by the operator due to the exporting of electricity at a loss.

(*) N.b.In both cases the price reflects a market distortion. Without EEE, the microgenerator is not paid a reasonable price for the distributed generation services it provides. With EEE, the network operator is not paid a fair price for the services it offers. A ‘fair rate’ will lie somewhere between the two extremes.

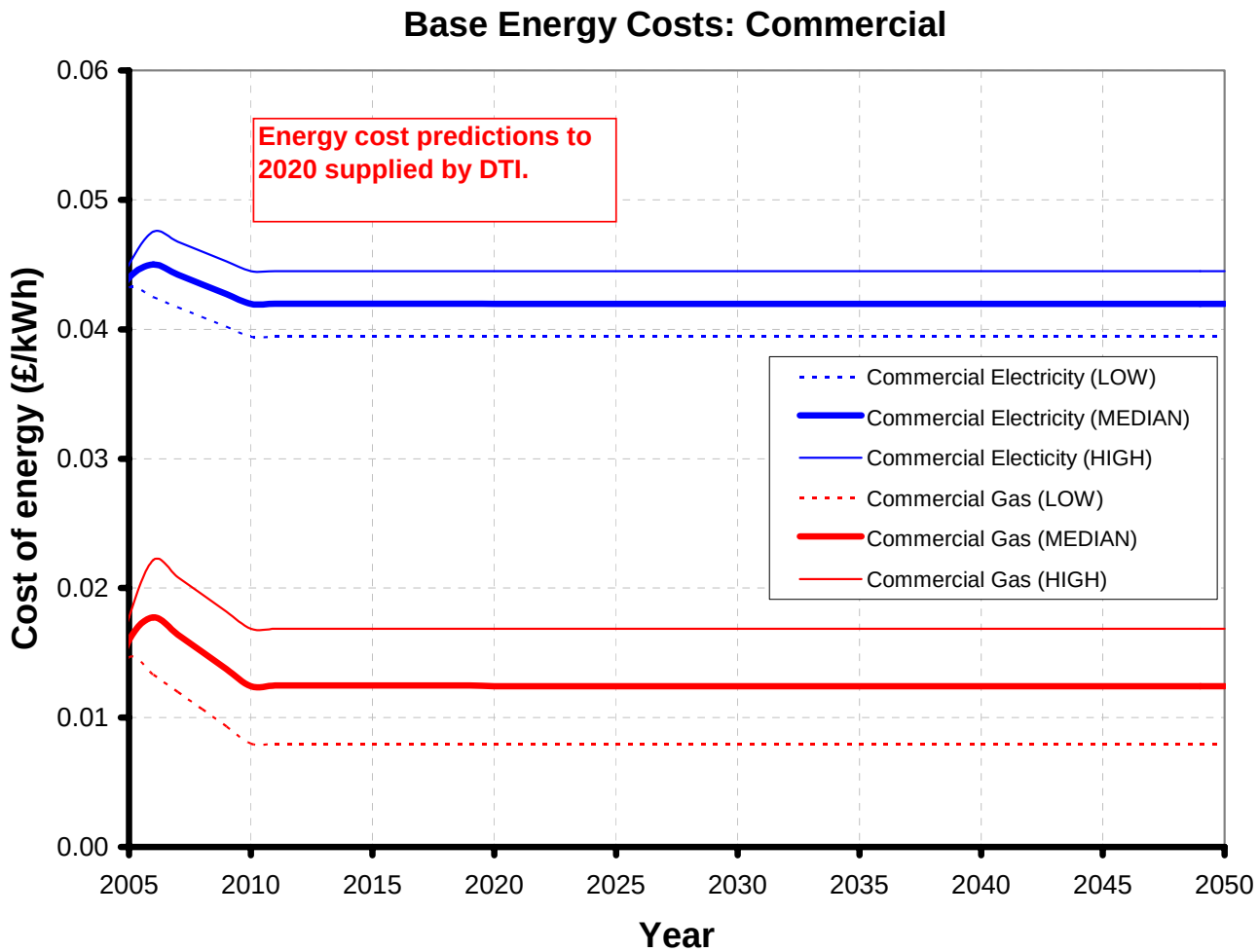
Contents

Gas and electricity baseline fuel costs for residential consumers are projected to 2050 (based on DTI figures for the near-term).



Note: The Economy 7 cost varies with supplier. The 2005 value of £0.04 / kWh represents the upper price range for night time electricity.

Gas and electricity baseline fuel costs for commercial consumers are projected to 2050 (based on DTI figures for the near-term).



To calculate the baseline costs of heating, a simple energy cost model assuming a condensing boiler is used.

Condensing gas boiler space and water heating

- The capital cost projections for a domestic boiler are modelled using a learning rate and growth value*.
- Limited cost reduction through learning is predicted: £65 / kW (2005) to £59 / kW (2050)#.
- Cost of thermal energy (£ / kWth) calculated using gas price projections**.
- The gas price is dominant in the cost of energy generated. The gas price trends are thus the major influence on changes in cost over time.
- Oil boiler heating is very slightly higher than gas but the difference is negligible when compared with microgeneration energy costs. Oil heating is therefore represented by gas heating.

Electrical heating

- Space and space/water heating: composed of 50% Economy 7 and 50% standard tariff electricity.
- Water heating: composed of 100% standard tariff electricity.

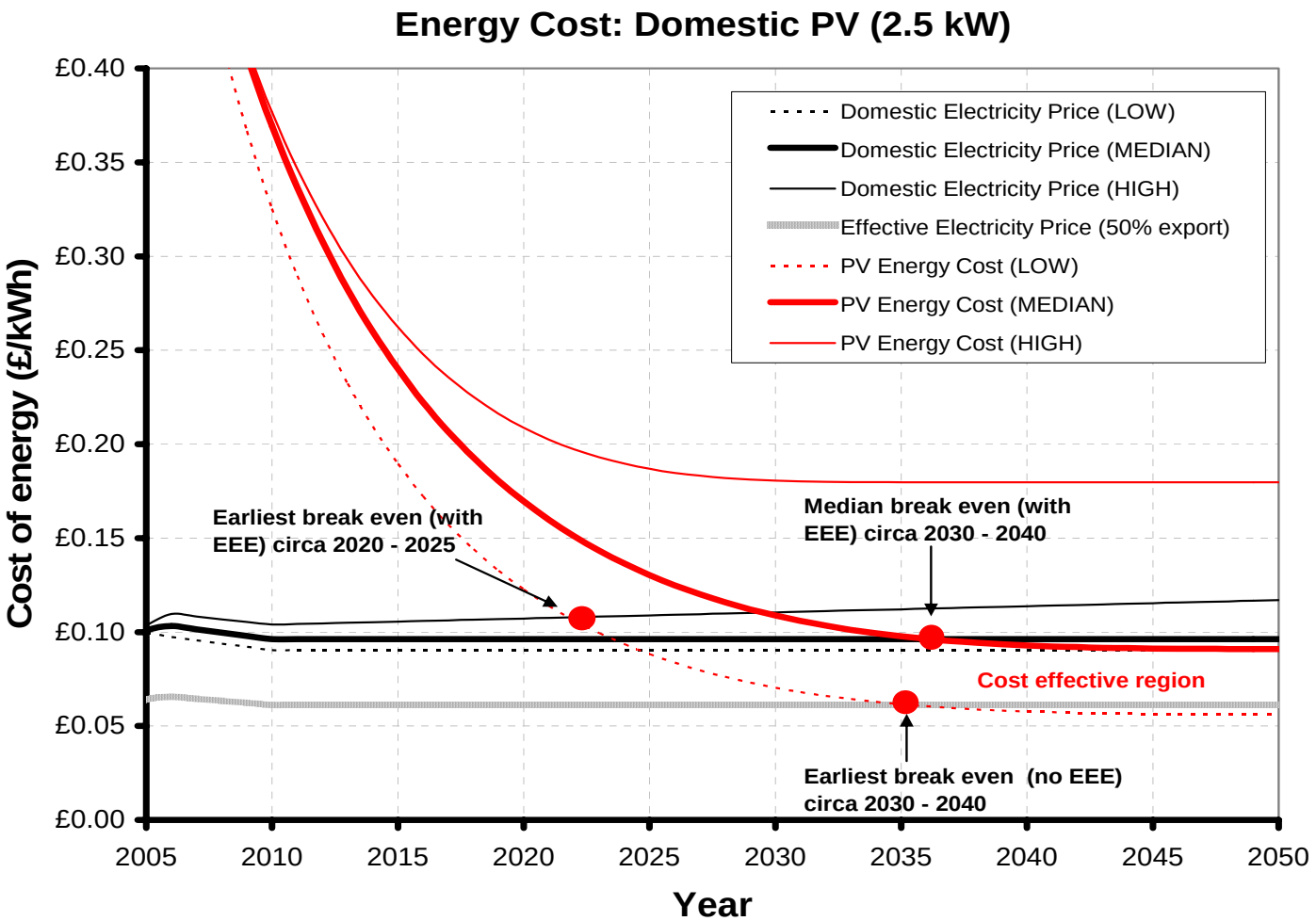
(*) A low learning rate of 4% and small growth combined with large installed capacity are used to give approximately 10 % cost reduction.
(#) £65 / kW is based on a 20 kW condensing boiler costing £45 / kW (commercial prices) with £ 300 installation costs and £100 in parts.
(**) The cost of energy is calculated for a 90 % efficient 20 kW boiler over a 15 year lifetime operating with 10 % load factor producing 17.5 MWth p.a. A 5% maintenance cost is assumed. 90% efficiency is typical for a condensing boiler although 86% is current regulatory minimum.

Contents

N.b. a detailed description of the technology cost projection model is provided in Appendix A1

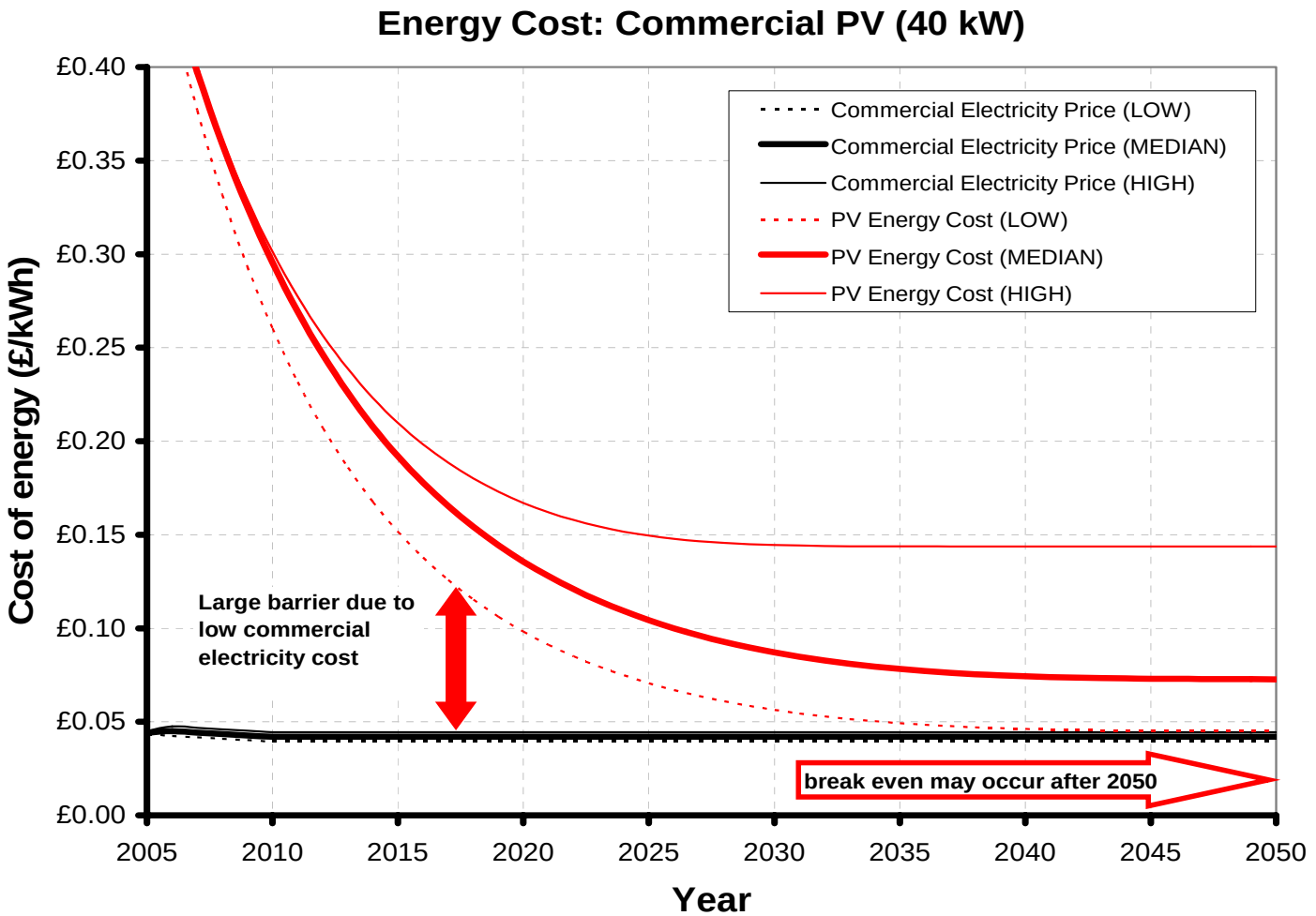
Domestic PV: projected generated energy costs. Break even is not achieved in the near-term.

- Break even is projected for the median scenario circa 2030 – 2040 with EEE.
- Without EEE, break even is not reached for the median scenario due to PV-generated electricity costs stabilising at a higher value than the non-EEE base level.
- A cost/performance breakthrough is necessary for economic operation without EEE.



Commercial PV: projected generated energy costs. Break even is not predicted before 2050.

- Commercial PV is not projected to be cost effective before 2050.
- This barrier is caused by high PV capital costs combined with the low commercial electricity prices (these are amongst the lowest in the EU)*.
- Commercial scale PV has certain niche markets where the cost barrier is reduced. These include applications such as off-grid remote power, and façades where PV costs are partially offset against alternative premium cladding materials.



(*) DTI Quarterly Energy Prices, June 2005

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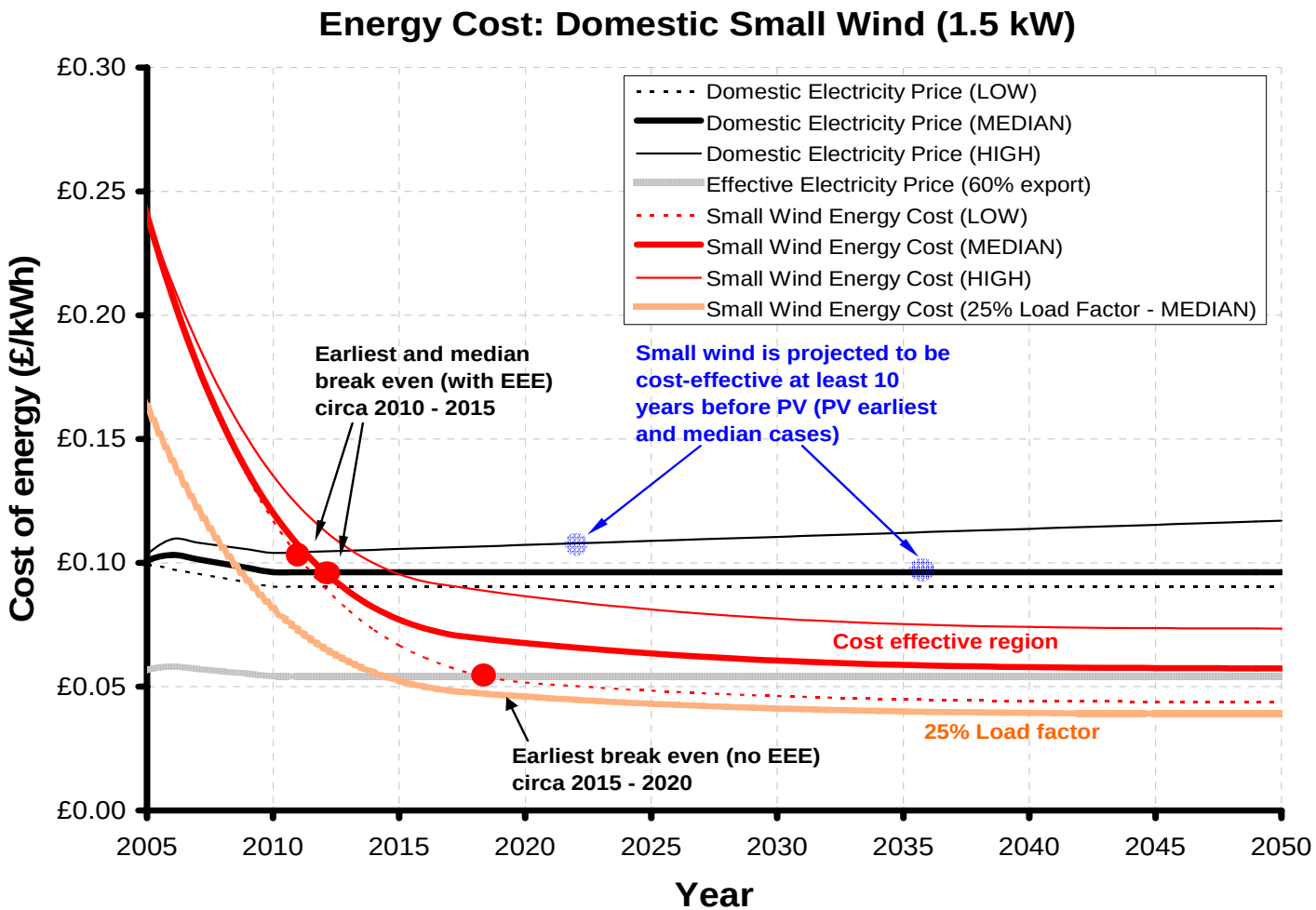
Domestic small wind: generated energy costs. Break-even predicted 2010 – 2015 (with EEE).

- Break-even for small wind is predicted circa 2010 – 2015.
- EEE is essential for break-even to be achieved under the median case.
- Increased load factors (e.g. location in an area with above-average wind speeds) could advance break even (with EEE) to 2005 – 2010.



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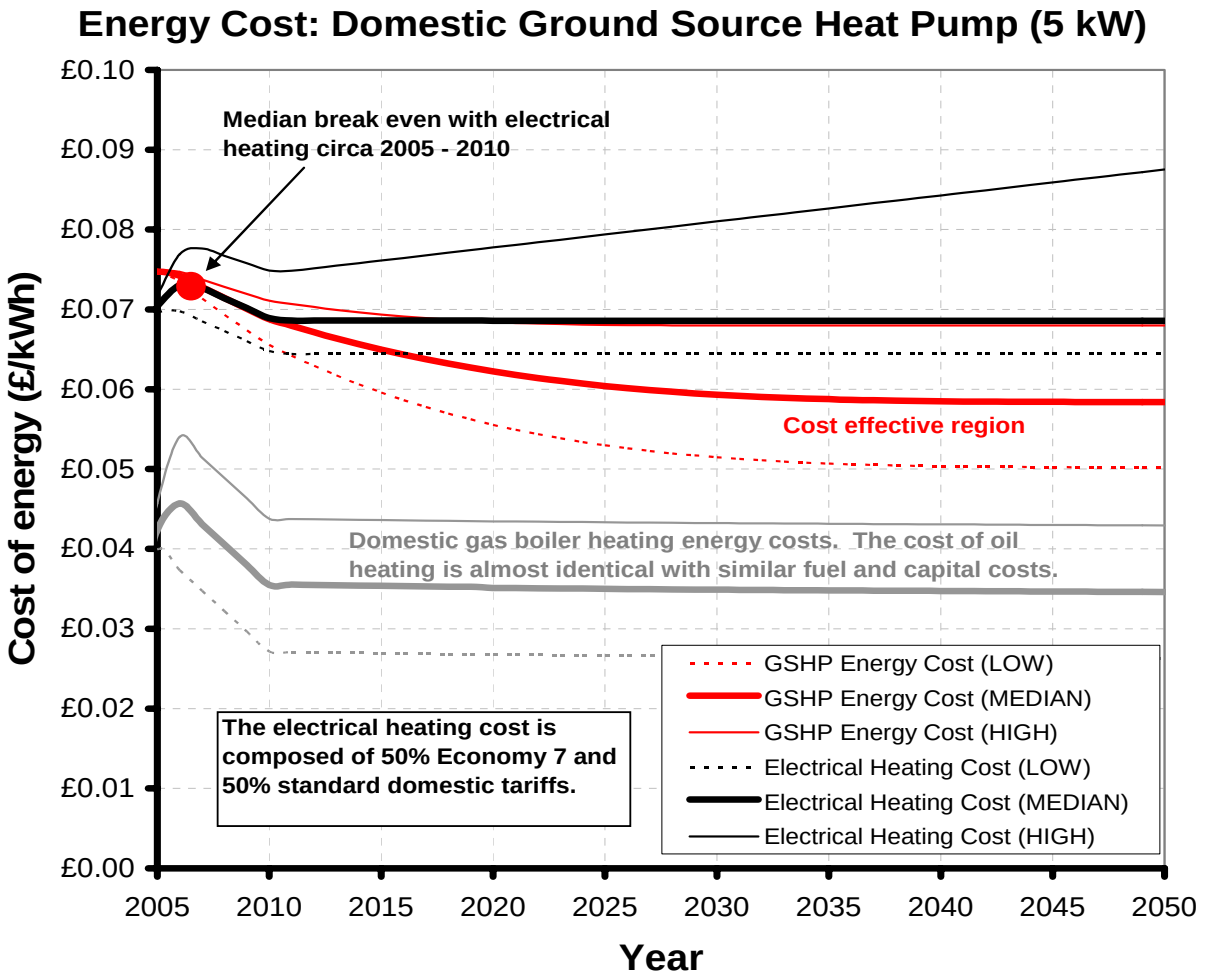
GSHP: generated energy costs. Break-even with electrical heating predicted 2005 – 2010. Unlikely to beat natural gas based heating.

- GSHP could become cost-effective with electrical heating by 2005 – 2010.
- Break-even is not predicted with oil and gas heating.
- The installed costs for GSHP as a replacement for electrical heating are likely to be higher. This would delay the break-even date*.



(*) This analysis only considers the boiler cost and not heating system. The additional costs of installing a wet-heating system as electrical heating replacement could make the GSHP installation un-economic. The difference for new-build could be less, but water heating systems are typically more expensive than electrical heating.

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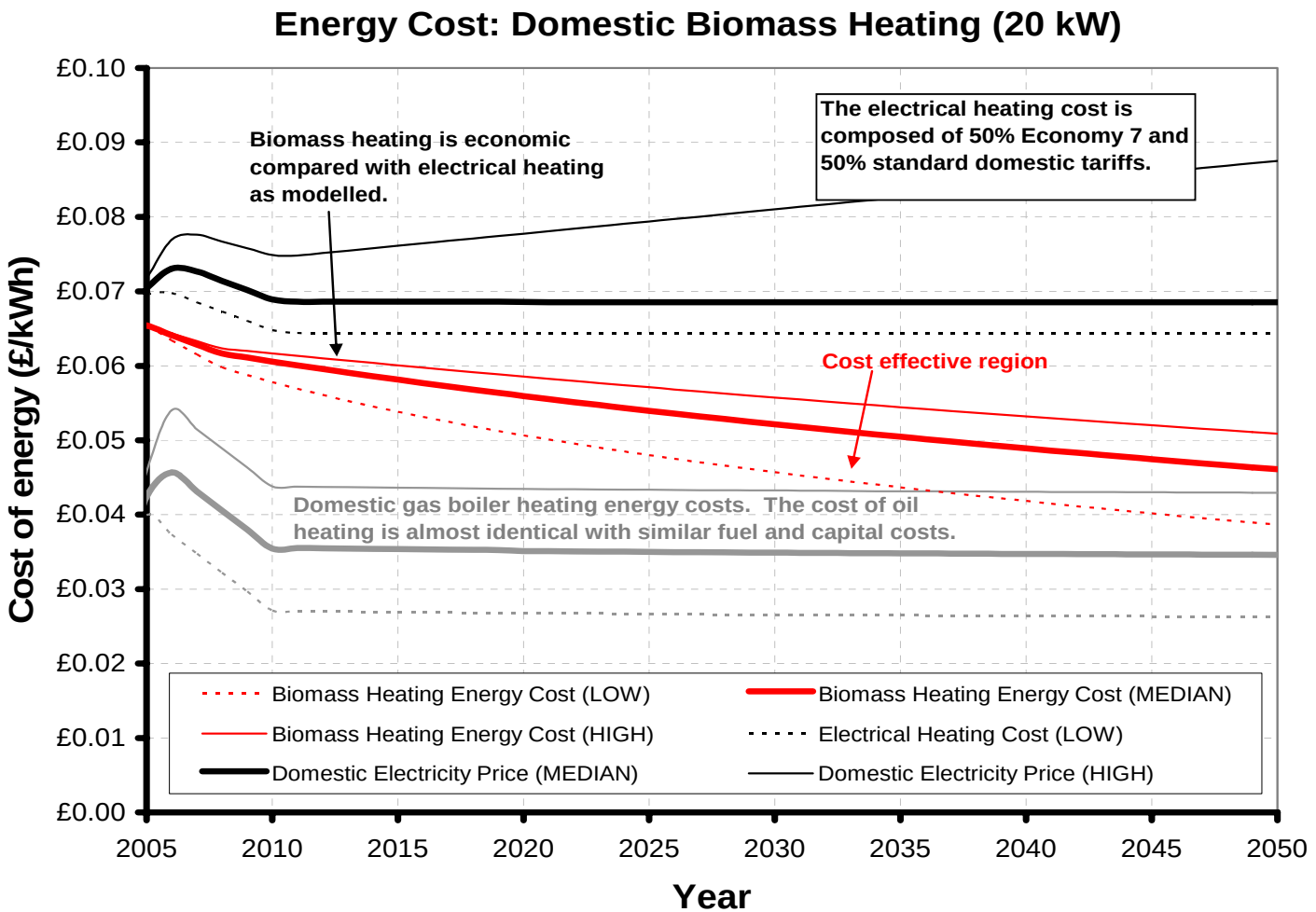
Biomass heating: biomass can be cost-effective as a replacement for electrical heating.

- Biomass boilers are currently cost effective with electrical heating as modelled *.
- Large reductions in capital cost are necessary for predicted break-even by 2050 with gas (or oil) heating.



(*) This analysis only considers the boiler cost and not heating system. The additional costs of installing a wet-heating system as electrical heating replacement could make the biomass installation un-economic. The difference for new-build could be less, but water heating systems are typically more expensive than electrical heating.

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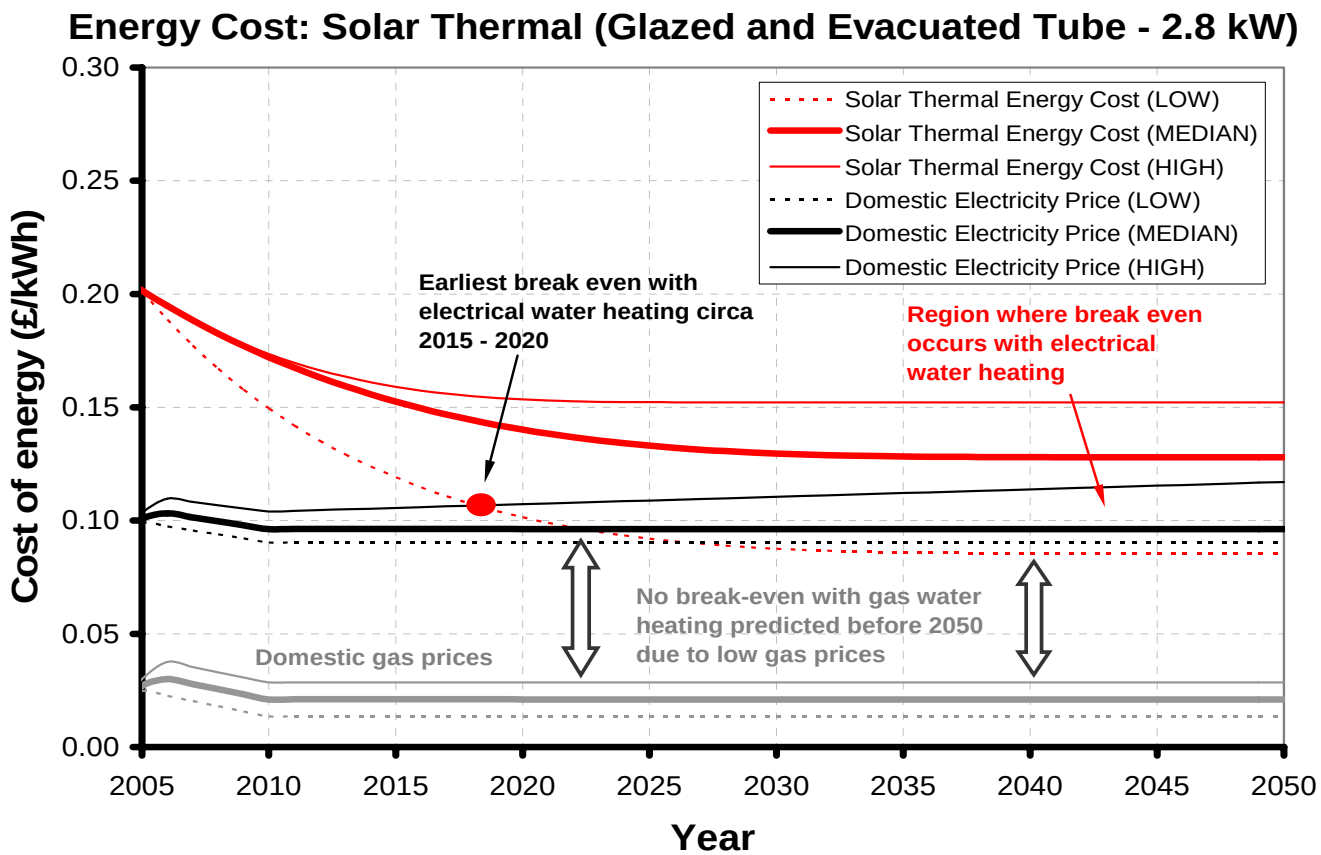
Solar water heating (active solar): reductions in generated energy cost are required for break even with electrical water heating.

- Break-even is not predicted for gas (or oil) boiler water heating. This is because of high capital costs combined with low oil and gas prices.
- Approximately 50 % capital cost reduction is necessary for break-even with electrical water heating by 2015 – 2020.



The complexity of Combined Heat and Power systems means that some modifications to the modelling procedure is required.

Three different types of CHP system are modelled:

1. Small domestic Stirling engine CHP.
2. Reciprocating engine CHP (both domestic and commercial).
3. Solid oxide fuel cells (SOFC).

The added complexity of combined heat and power generation requires some modifications to the cost-of-energy model:

- **Capital costs for CHP systems**
  - CHP capital costs are expressed in terms of their electrical capacity, **£/kWe.**
  - The heat output is linked to the electrical capacity by the heat-to-power ratio.
  - Energy costs are expressed in £/kWh_{total}, i.e. the total kWh energy output.

- **Hybridised base energy costs:**
  - The combined base cost for CHP is hybridised using the output heat to power ratio.
  - For example with 33 % electrical capacity and 67 % thermal capacity:

Combined base cost / kWh = 0.33 × (effective electricity price / kWhe) + 0.67 × (replaced heating price / kWhth)

Analysing the cost-effectiveness of CHP operation.

Calculating the cost of energy

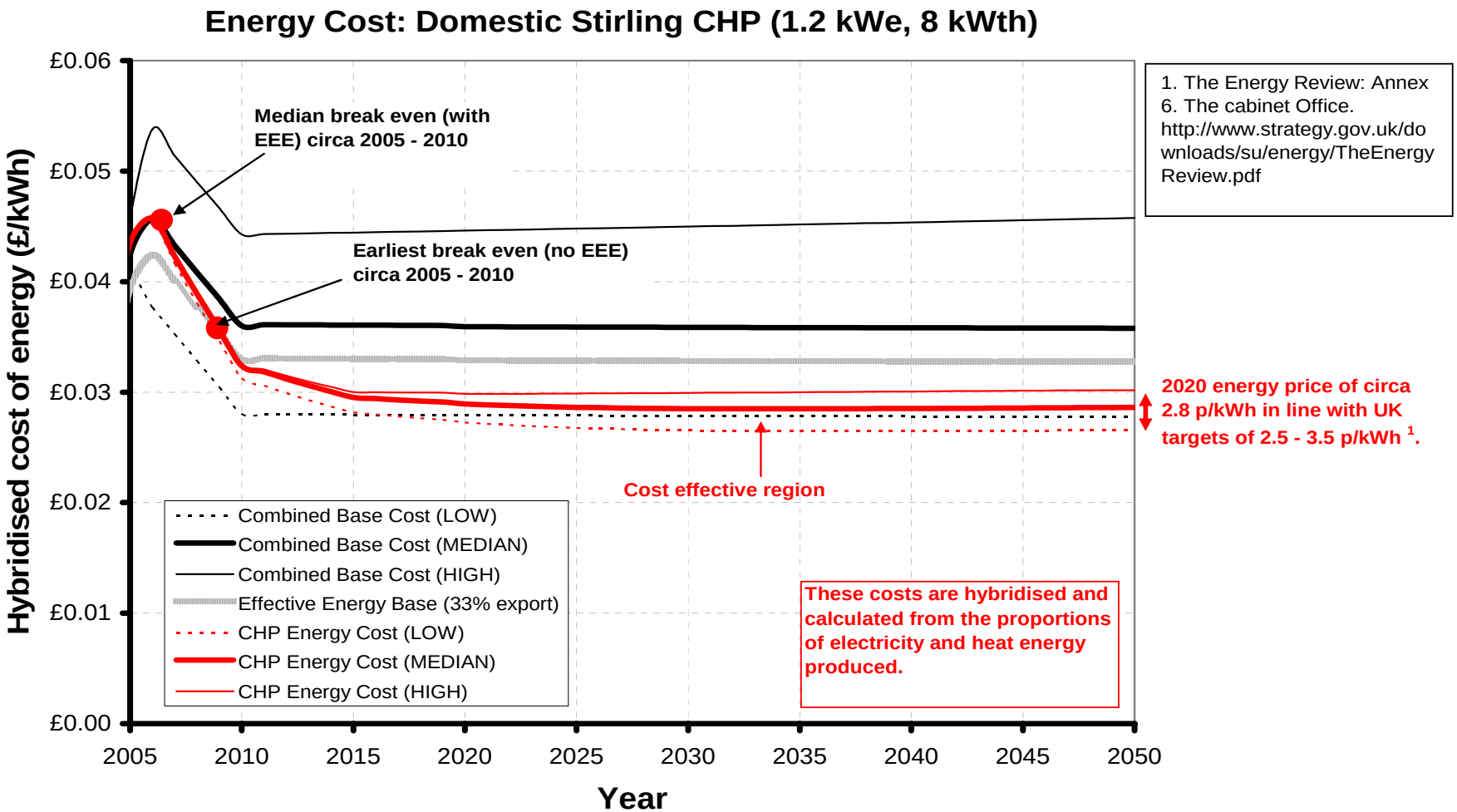
- The energy costs are expressed as a hybridised value, calculated by dividing the total investment costs per annum (annualised capital costs + fuel cost) by the total energy produced (the sum of electrical and thermal): £/kWh_{total}.
- CHP technologies are modelled operating in 100% CHP mode. This ignores periods of time when the unit may operate in heating mode only as current designs operate on a CHP-first principle.
- To account for 100% CHP mode operation, calculations use the "on-cost" of the CHP system (i.e. the additional price over the replaced heating boiler). This on-cost is the price paid for the CHP capability at the time of boiler replacement.
- To remain consistent, for CHP the baseline energy cost is modified (e.g. gas-boiler heating cost per kWh) by removing the boiler capital cost from the cost of energy calculations.

CHP load factor

- The load factors are based on the average energy demand values from a typical system per annum*.
- The systems are sized for operation in their optimum regime with different building types. E.g. a high heat-to-power ratio system has a high thermal output and is suitable for a larger or less well insulated property, whilst a low heat-to-power ratio system is more suitable for a smaller heating demand or new build property.

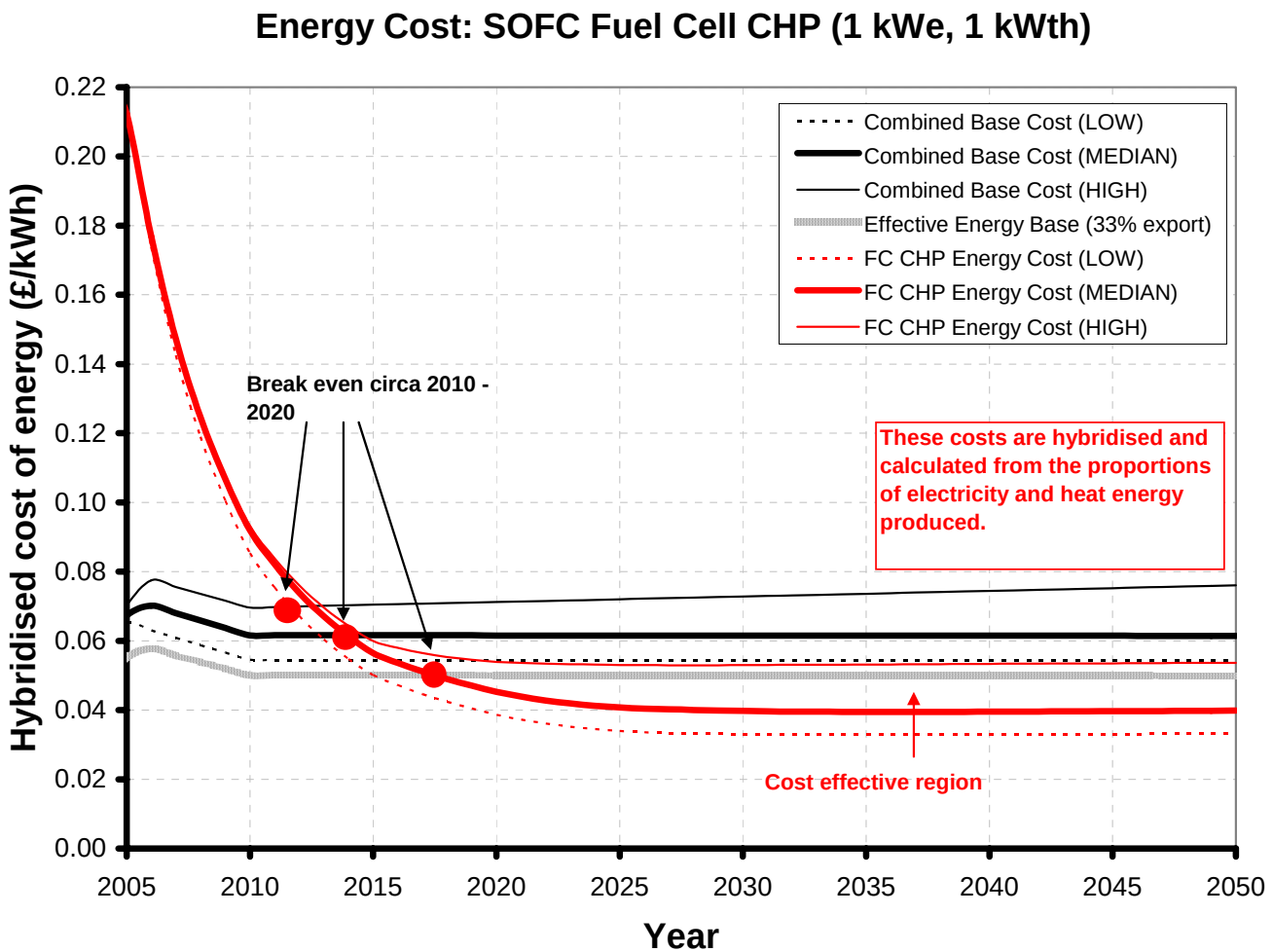
(*) These values are based on Element Energy experience of CHP system modelling and sizing for residential and commercial installations.

Stirling CHP: generated energy costs. Break-even predicted 2005 – 2010.



SOFC 1 kWe CHP: generated energy costs. Break-even predicted 2010 – 2015.

- Median break-even predicted (both with and without EEE) circa 2015, based on detailed discussions with FC manufacturers who predict these costs are achievable in this time period.
- The 1 kW Fuel cell CHP has the potential to be the most cost-effective technology: 2050 costs are predicted to be 1 p/kWh below the base cost (with no EEE) and 2 p/kWh (with EEE).
- The break-even points are close due to large capital cost reductions in the short term.



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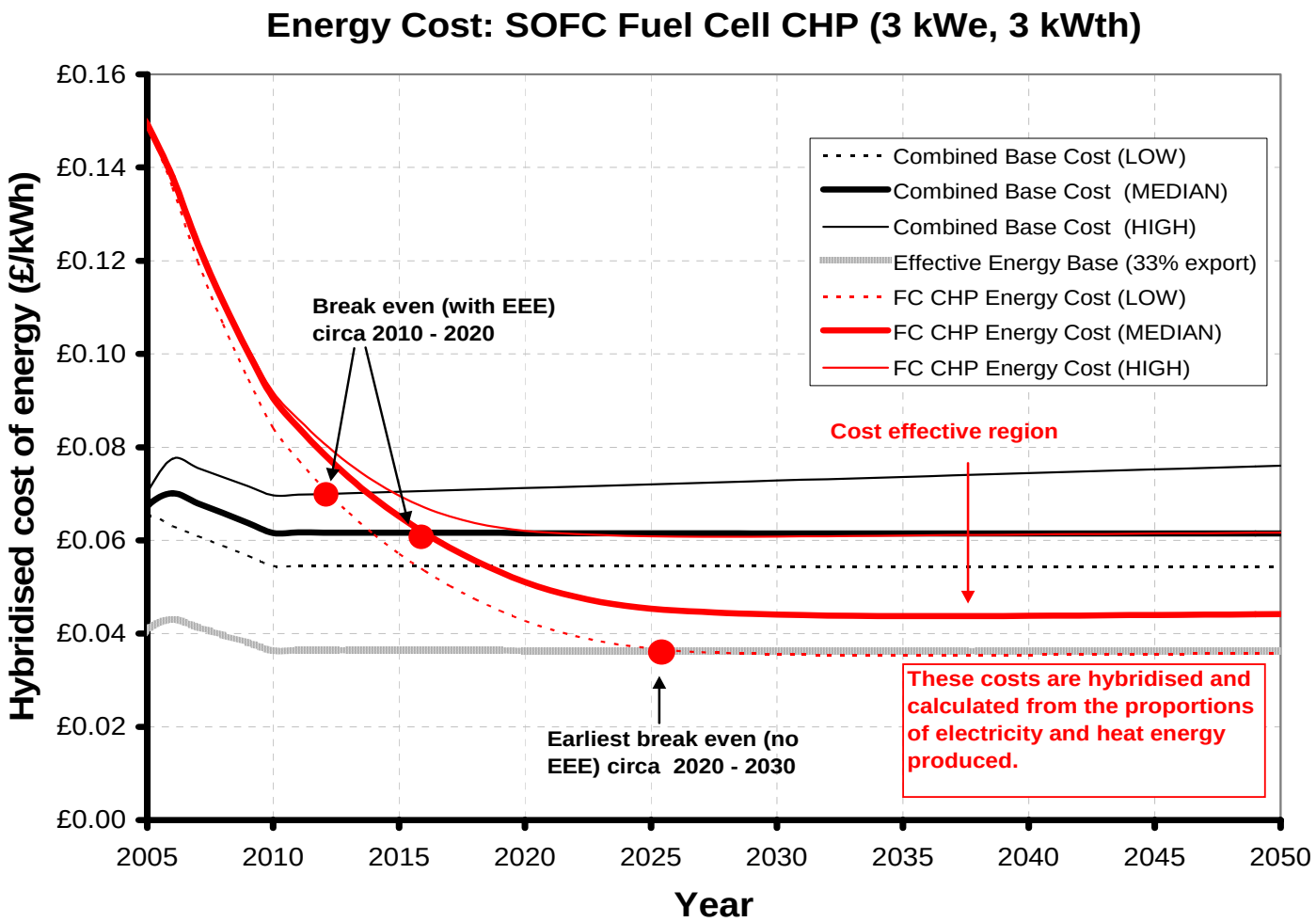
SOFC 3 kWe CHP: generated energy costs. High export percentage significantly delays break-even without EEE.

- The 3 kWe is an interesting case where a small CHP system is installed with an average electrical output larger than that of a typical house, implying large exports*.
- Break even for EEE scenarios predicted circa 2015 similar to 1 kW system.
- EEE is essential for economic operation: The median cost of generated energy is predicted to stabilise above the non-EEE base level (with 72% of electricity exported).



(*) This approach is consistent with the generally agreed optimum of sizing CHP systems to the heat load.

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Contents

N.b. a detailed description of the technology cost projection model is provided in Appendix A1

Detailed technology cost projections are included in Appendix 1, the following slides summarise the results for each technology.

PV

- The cost of energy from PV in the UK is currently very high due to large capital costs of the technology. To maintain uptake, incentives are required until circa 2030 to achieve cost equivalence.
- Domestic PV could be cost-effective with EEE circa 2030. Without EEE, cost-effectiveness can only be achieved with a cost/performance breakthrough (i.e. lower bound cost assumptions).
- Cost effectiveness for commercial PV is not predicted before 2050 due to the low commercial electricity prices except in specific high value markets.

Wind

- Under the median scenario, domestic small wind could be cost effective by 2010 – 2015, but always requires EEE. For very high wind speed sites (>6 m/s), small wind will be cost effective before 2010.
- Without EEE small wind is unlikely to achieve cost effectiveness before 2050.
- Cost-effectiveness for commercial small wind (10 kW) is delayed by circa 5 years due to the lower commercial electricity cost.

Hydro

- Smaller hydro systems (0.7 kW) can be cost-effective with EEE. Significant cost reductions are required for break-even without EEE.
- Cost-effectiveness for larger (10kW) systems supplying all their electricity to commercial premises is predicted only if there are significant reductions in capital costs. This is predicted for 2015 – 2020 with EEE and circa 2050 without EEE.

Summary – heat generation.

CHP

- EEE metering enables the break-even of Stirling and small reciprocating engine CHP systems circa 2015. The absence of EEE delays this by approximately 5 years.
- In the long term, fuel cell CHP is potentially the most cost-effective technology with break even circa 2015 and generated energy costs up to 2 p/kWh below baseline costs by 2050.
- The small 1 kW electricity-led fuel cell CHP achieves cost-effectiveness with EEE circa 2010 - 2015 and 5 years later without EEE depending on technology cost assumptions.
- Decentralised generation with a 3 kW heat-led fuel cell CHP implies substantial electricity export and requires EEE for cost-effectiveness. Without EEE, break-even is not predicted in the median cost scenario.

Solar water heating

- Solar water heating does not break-even with gas boiler water heating, and will require large cost reductions to break-even with electrical water heating by 2015 – 2020.

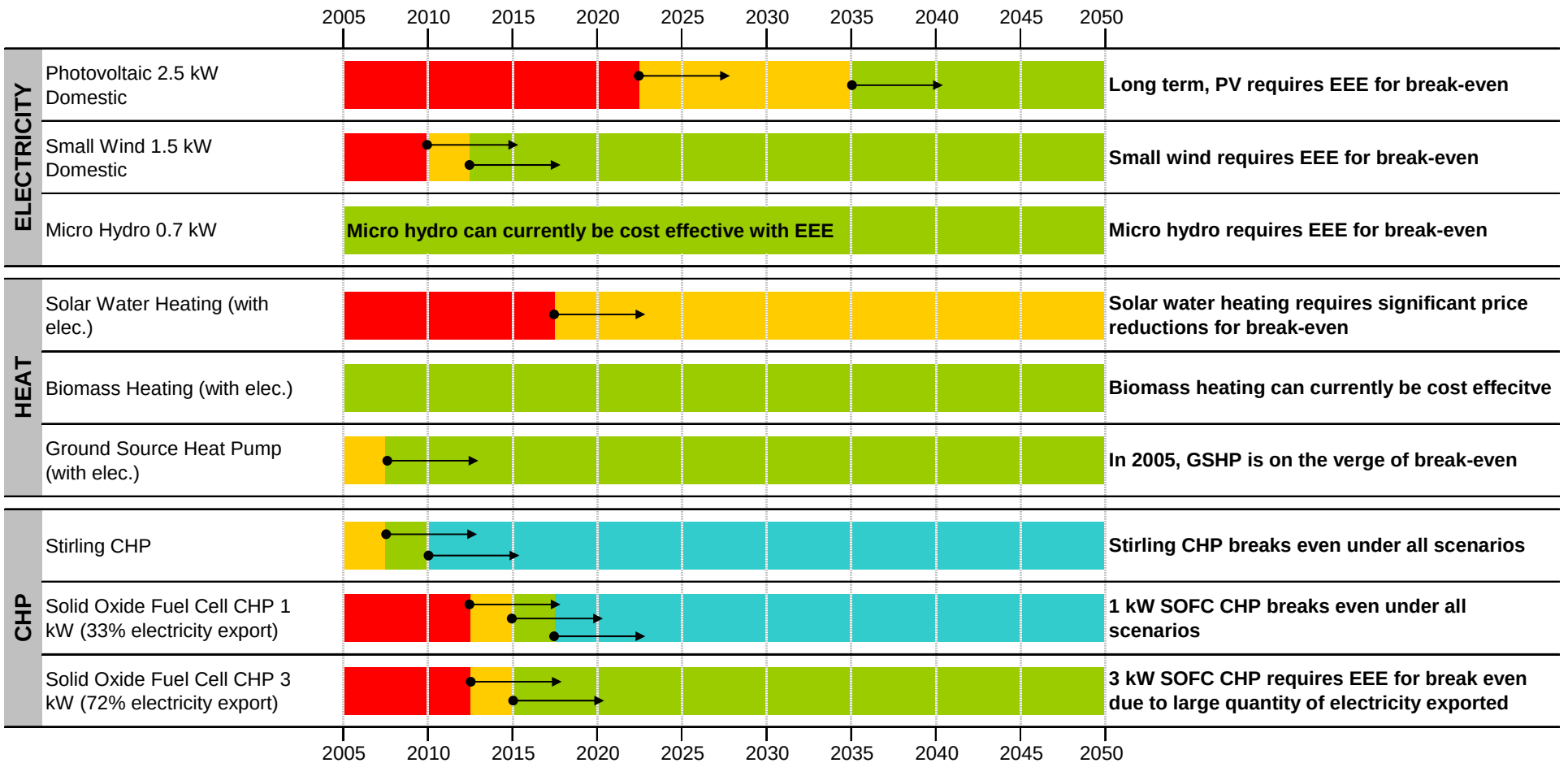
Biomass heating

- Biomass heating can currently be economic compared with electrical heating, but large cost reductions are necessary for break-even with gas heating (i.e. the lower bound cost assumptions).

Ground source heat pumps

- GSHP shows potential for break-even with electrical heating circa 2005 – 2010, but is not projected to be cost-effective with gas heating.

Summary of expected break-even points for different scenarios.



Key

Scenario (EEE: Energy Export Equivalence - Placing a higher value on microgen electricity exported to the grid)

Not cost effective

Earliest break even (with EEE for elec. technologies)

Median break even (with EEE for elec. technologies)

Median break even (with no EEE for elec. technologies)

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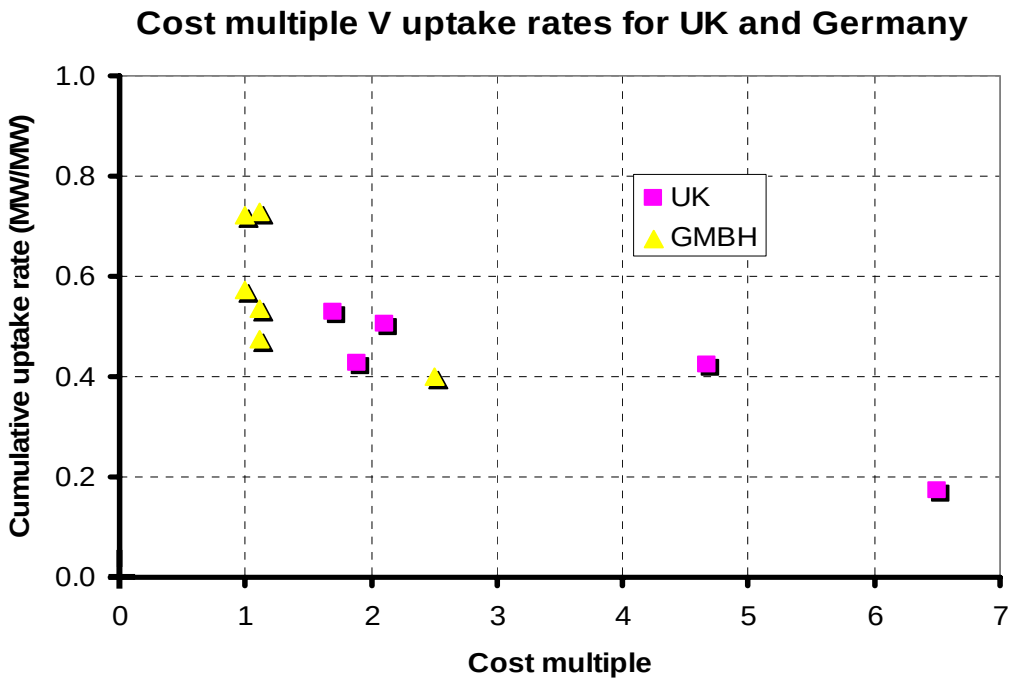
Contents

N.b. a detailed description of the **uptake model** is provided in Appendix A2

The uptake model is based on the willingness of UK consumers to purchase microgeneration at different delivered energy costs.

- **A detailed description of the uptake model is provided in Appendix A2.**
- Some uptake models assume the population behaves rationally; that there is no investment when the cost of energy is above a cost effective level*.
- Empirical data from the microgeneration market suggests otherwise. This graph shows growth rates in the UK and German PV markets, over recent years**. The graph clearly shows growth even when the technology is significantly non-cost effective.
- The graph shows that uptake rates are substantially higher when the cost of energy is economic. (In Germany, a feed-in tariff is structured to provide energy at a cost multiple close to 1).



Cost multiple is defined as:

$$\frac{\text{(cost of energy from microgeneration)}}{\text{(cost of energy from incumbent energy supply)}}$$

(*) The INVERT uptake model; Energy Economics Group, University of Vienna. (www.invert.at)

(**) Cost multiple is defined as the cost of microgen energy divided by the baseline (commercial) cost of energy. If Cost Multiple > 1, the technology is not cost effective.

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There is considerable uncertainty associated with the “willingness to pay” for microgeneration technologies.

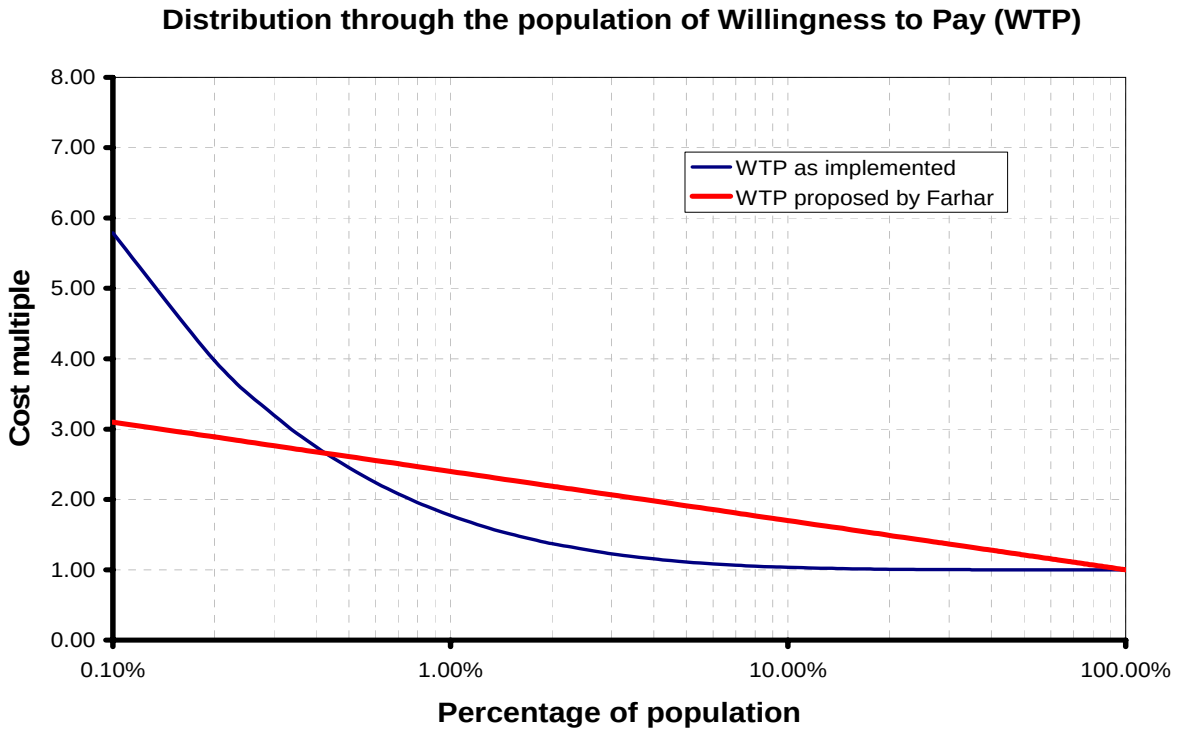
- The development of an uptake model, particularly one which could be dependent upon highly irrational decision making, is open to significant uncertainty. The distribution through the population of “willingness to pay” is vital in the prediction of uptake rates.
- There is very little data in the literature with regards to such models, however one paper is often cited for “willingness to pay” data.
- The Farhar* paper collated responses from national polls in the US regarding willingness to pay an on-cost on utility bills for “green” electricity.
- The paper concludes that most of the population is willing to pay an on-cost for green energy (between 30% and 90% of the population). This seems high, and is much higher than participation rates in utility-led green energy programmes (which is circa 1% of the population), suggesting a positive response bias skewed towards renewables**.
- The uptake model used by the US Department of Energy*** shows much more price/demand elasticity.
- Therefore, a more conservative WTP curve is proposed for the current model.
- Microgeneration products will have a different WTP from green electricity tariffs. Willingness to pay for microgeneration may be lower than for green tariffs because of the additional issues associated with purchase and installation. Alternatively it may be higher because it is more conspicuous.

(*) Farhar, B.C; “Willingness to Pay for Electricity from Renewable Resources: A review of Utility Market research”; NREL July 1999

(**) Jensen et al, “An analysis of residential preferences for green power”, Uni. of Tennessee, 2004.

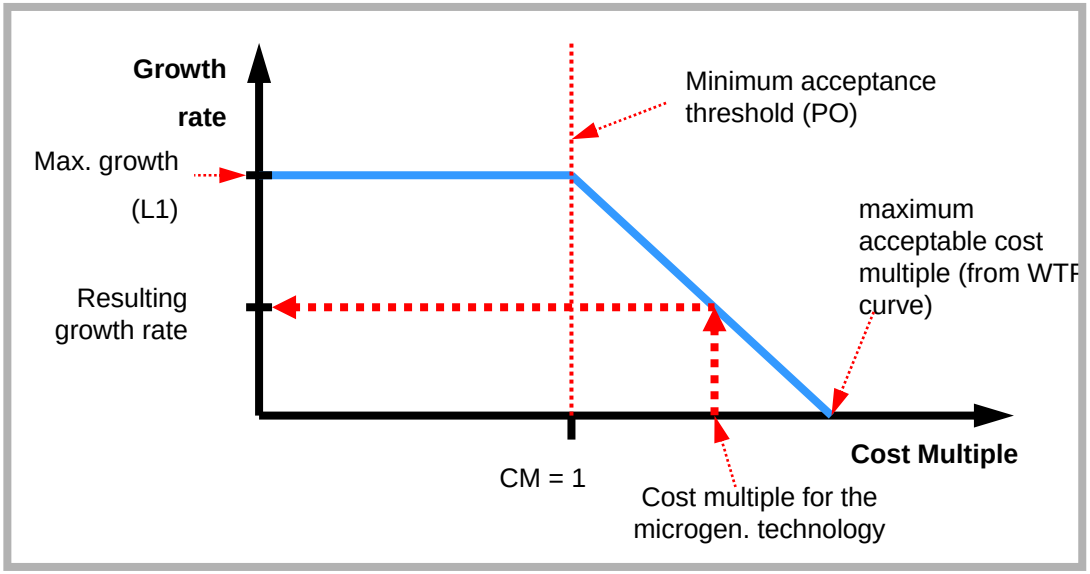
(***) Boedecker et al; “Modelling Distributed electricity generation in the NEMS building Modules“, US Doe 2000. This model suggests that highly commercial technologies (i.e. with payback periods of 1 to 2 years) are taken up relatively slowly (circa 20 years required for saturation).

The willingness to pay used in this model assumes that only a small fraction of the population will accept high microgen energy costs.



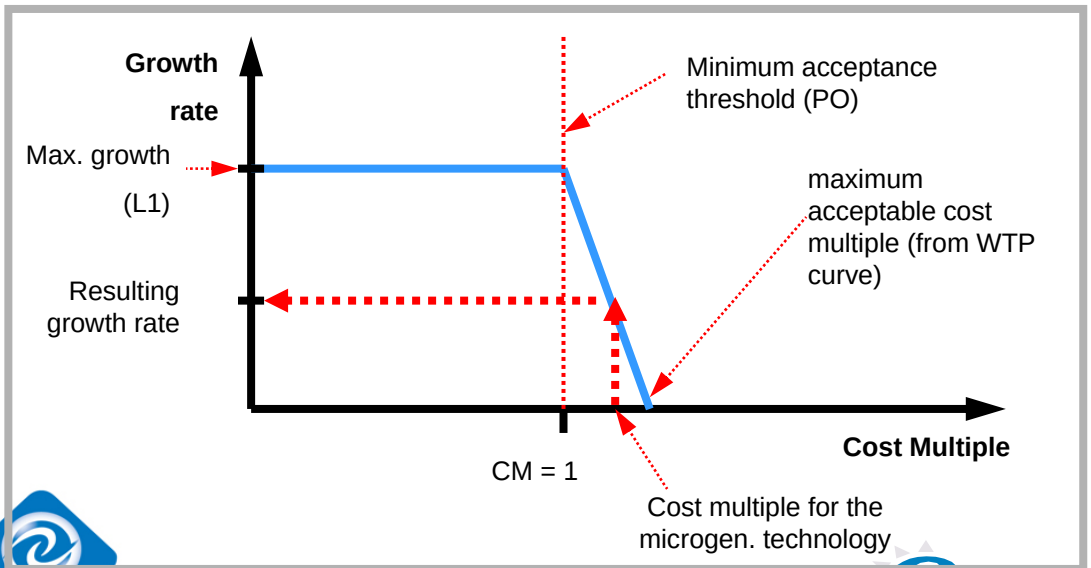
- The graph above shows the distribution of WTP through the population, as proposed by Farhar and as implemented in the current model.
- The implemented WTP curve corrected two failings of the Farhar data:
  - WTP for the most innovative section of the population (0.1%) was too low, preventing any uptake of certain high cost technologies (such as PV)
  - WTP for the majority of the population was too high even though this is obscured for an energy technologgy; this now approaches unity for most of the population.

The level of uptake of microgeneration is modelled as a function of the cost multiple, which varies with the installed capacity.



For LOW installed capacity

- For a small percentage of the population (the innovators), the maximum acceptable cost (taken from the WTP curve) is high.
- Therefore, technologies with high cost multiples can be taken up (although uptake rates are higher if the technology is more cost effective).
- A maximum growth rate is imposed when the cost multiple is below one.



For HIGH installed capacity

- For most of the population, the maximum acceptable cost (taken from the WTP curve) is much closer to one.
- The cost of energy must reduce over time if growth is to continue.
- If cost does not reduce quickly enough, the market stagnates.

The model allows a variation of three critical parameters relating to consumer behaviour.

Heterogeneity of acceptance levels in the current model

Varying maximum acceptable cost:

- This is Willingness to Pay, and varies through the population, from innovators (with a high WTP) to late adopters (with a much lower WTP).

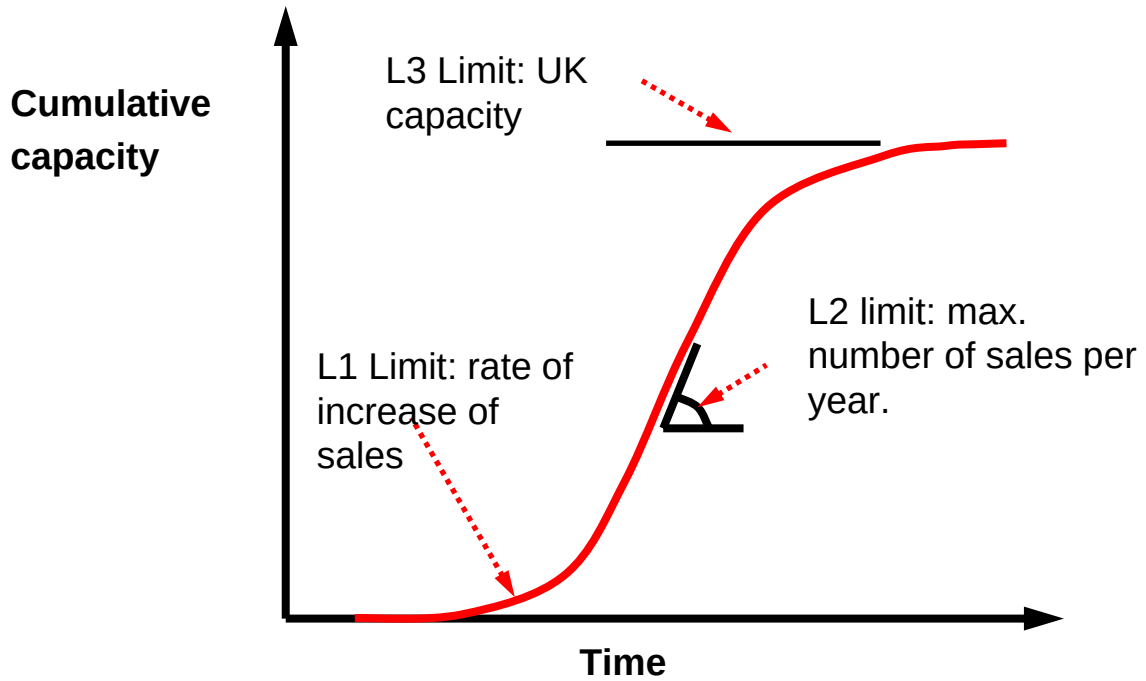
Varying L1: maximum growth rate

- Initially, the maximum growth rate that can be achieved – even if the technology is made very cost effective, is 70%. The actual value may differ for different technologies and needs further research.
- Observation is that most technologies find it difficult to sustain > 30% when significant capacity is reached.
- Therefore, as capacity increases (to levels equivalent to mass uptake), L1 tends towards 30%.

Varying PO: minimum acceptance threshold

- The acceptance threshold is typically set at one. However, varying this value can have a substantial effect on uptake levels.
- More sceptical consumers would have a lower P0 (e.g. 0.8). This means that the cost of energy must be significantly lower than the baseline before the customer is prepared to invest. This would be consistent with observations for home insulation, although consumer reactions to microgeneration are likely to be different.

The model also limits the rate of uptake of each technology according to maximum annual sales (L2) and total theoretical capacity (L3).



Three limits to uptake are imposed on the model

- L1 – maximum rate of growth of the market per year (previous slide).
- L2 – Maximum number of sales per year
- L3 – UK technical capacity to accept technology

Contents

The following slides provide model outputs for the base case.

The following baseline results are based upon scenarios which are:

- without support or government intervention of any kind.
- without energy export equivalence (i.e. any excess electricity is sold back to the grid at a price which is significantly lower than electricity purchase price). Placing a “fairer” value on exported electricity can have a primary effect on certain technologies.
- based on a “rational” consumer scenario: interest rates of 8%, loan period equal to lifetime of technology, ultimate cost threshold (P0) = 1 *.

Altering the above scenarios can result in significant changes to uptake

- These are addressed in subsequent sections.

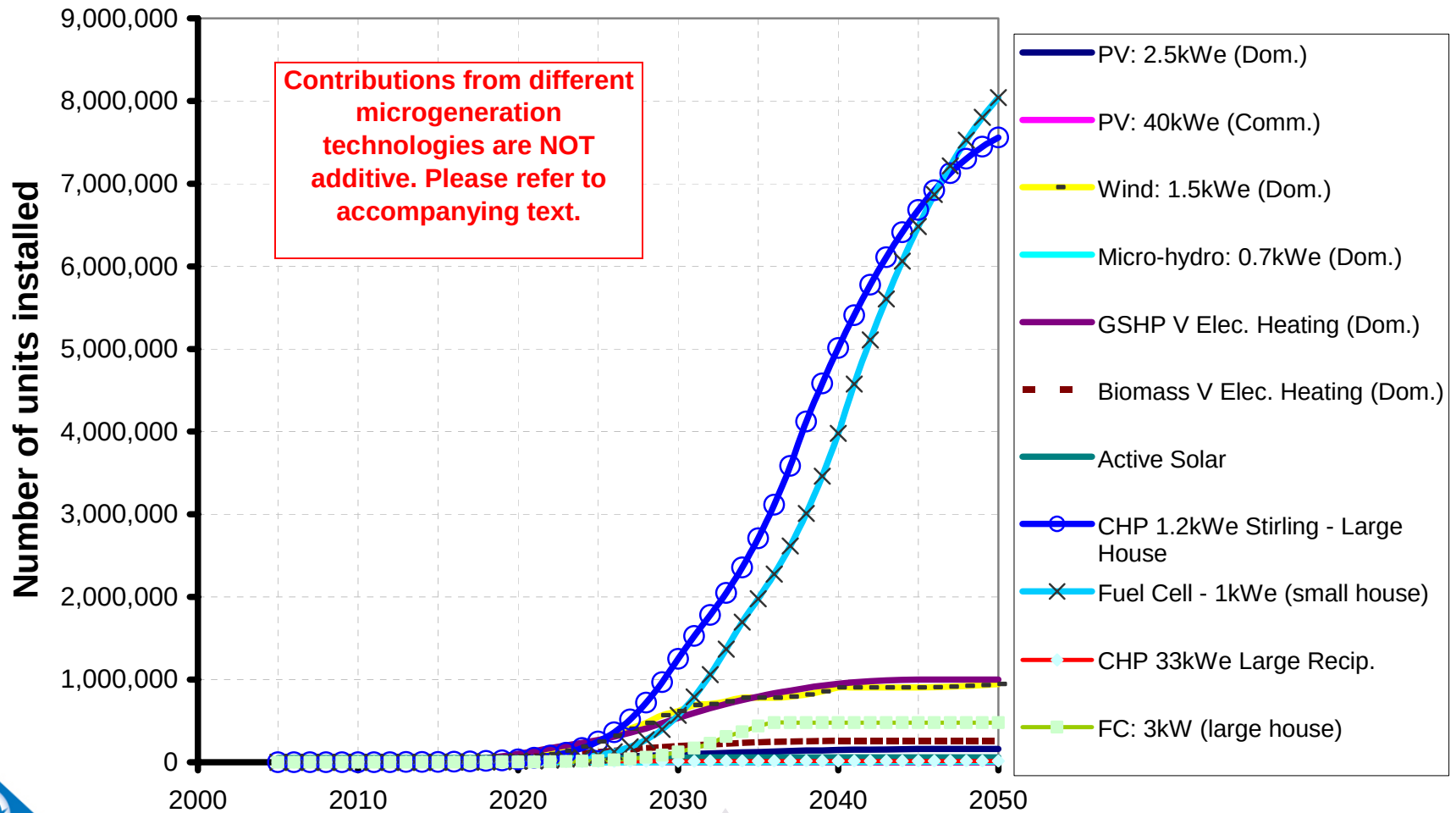
Assumptions underlying the model are provided in Appendix A2.2

(*) This means that for most of the population, a technology must produce cost effective energy before they will invest.

Long term, small CHP technologies (Stirling + Fuel cell) could dominate, with some small wind, biomass and GSHP.

The graph illustrates the yearly model outputs for a wide range of technologies without government intervention.

Cumulative number of installed units of each technology type



These uptake levels could occur without intervention or support (but these levels would be accelerated with intervention).

Units installed (*)	PV: 2.5kWe (Dom.)	PV: 40kWe (Comm.)	Wind: 1.5kWe (Dom.)	Micro-hydro: 0.7kWe (Dom.)	GSHP V Elec. Heating (Dom.)	Biomass V Elec. Heating (Dom.)	Active Solar	CHP 1.2kWe Stirling - Large House	Fuel Cell - 1kWe (small house)	CHP 33kWe Large Recip.	FC: 3kW (large house)
2010	2,402	250	1,025	334	2,260	2,792	51,071	614	210	1,760	54
2020	30,751	660	48,599	519	100,838	61,064	51,071	35,145	11,428	7,655	2,584
2030	95,112	1,502	620,830	1,773	537,900	195,550	54,974	1,250,977	566,983	13,563	122,545
2050	160,542	2,519	944,917	9,910	1,000,000	260,000	59,017	7,556,859	8,040,415	17,000	478,797

The model predicts substantial uptake of appropriately-sized domestic CHP technologies; Stirling engines for large heat demand houses and fuel cells for properties with lower heat demands. The oversized fuel cell (3 kWe) does not achieve substantial penetration as exported electricity is valued at a low level in the model.

Uptake of renewable heat (GSHP and biomass) technologies is significant where competition is with electric heating.

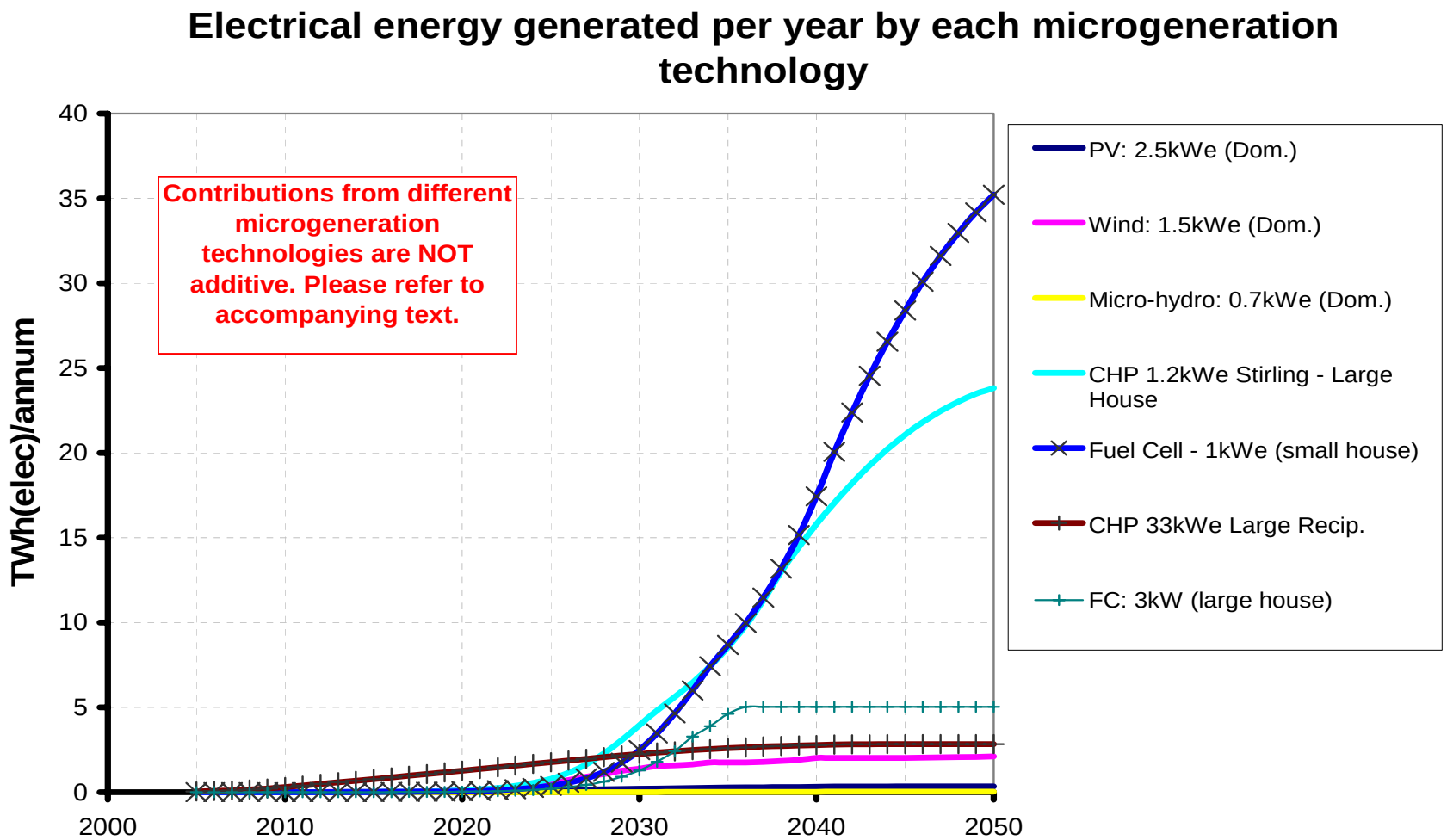
Small wind achieves some mass market penetration from 2015, once equipment cost reduction allows competition with grid electricity. However, lack of energy export equivalence prevents more widespread uptake.

There is very limited deployment of PV, solar water heating or micro-hydro before 2050, with no subsidy, due to high technology cost.

(*) Note that these numbers of installed units is based on a typical unit size as indicated in the appendix. Therefore, the numbers in the table need not match the figures given on page 22.

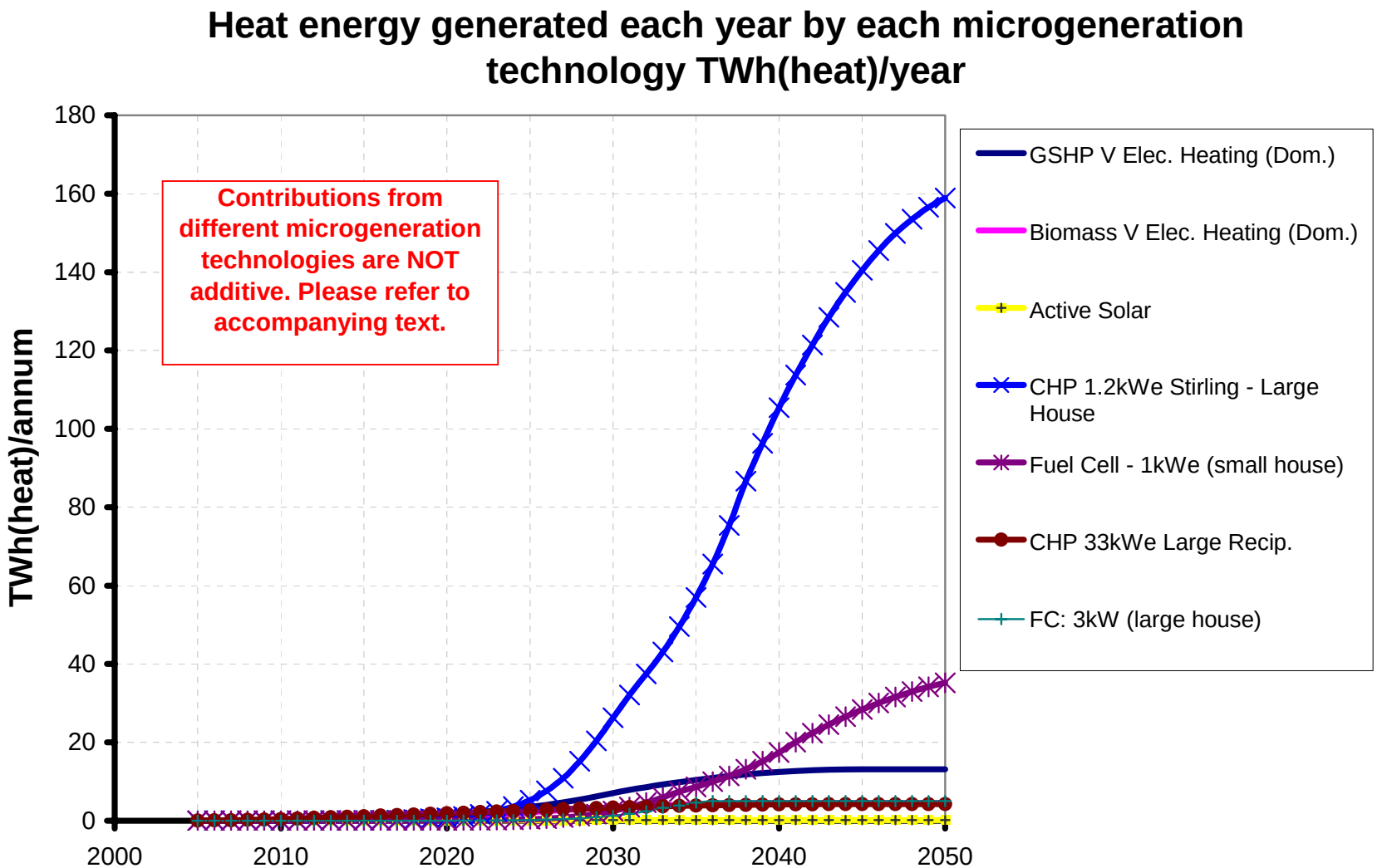
(**) Also note, this represents a totally unsubsidised scenario – i.e. it does not include existing subsidy schemes e.g. Clear Skies (hence low uptake of e.g. Active Solar)

Without support, microgeneration technologies could provide up to 20% of UK electricity generation by 2050.



Total UK electricity generation is currently 380 TWh per year.

Stirling engines providing heat to larger dwellings would provide a large fraction of the current UK domestic heating demand.



Current UK domestic heat demand is approximately 450 TWh per year.

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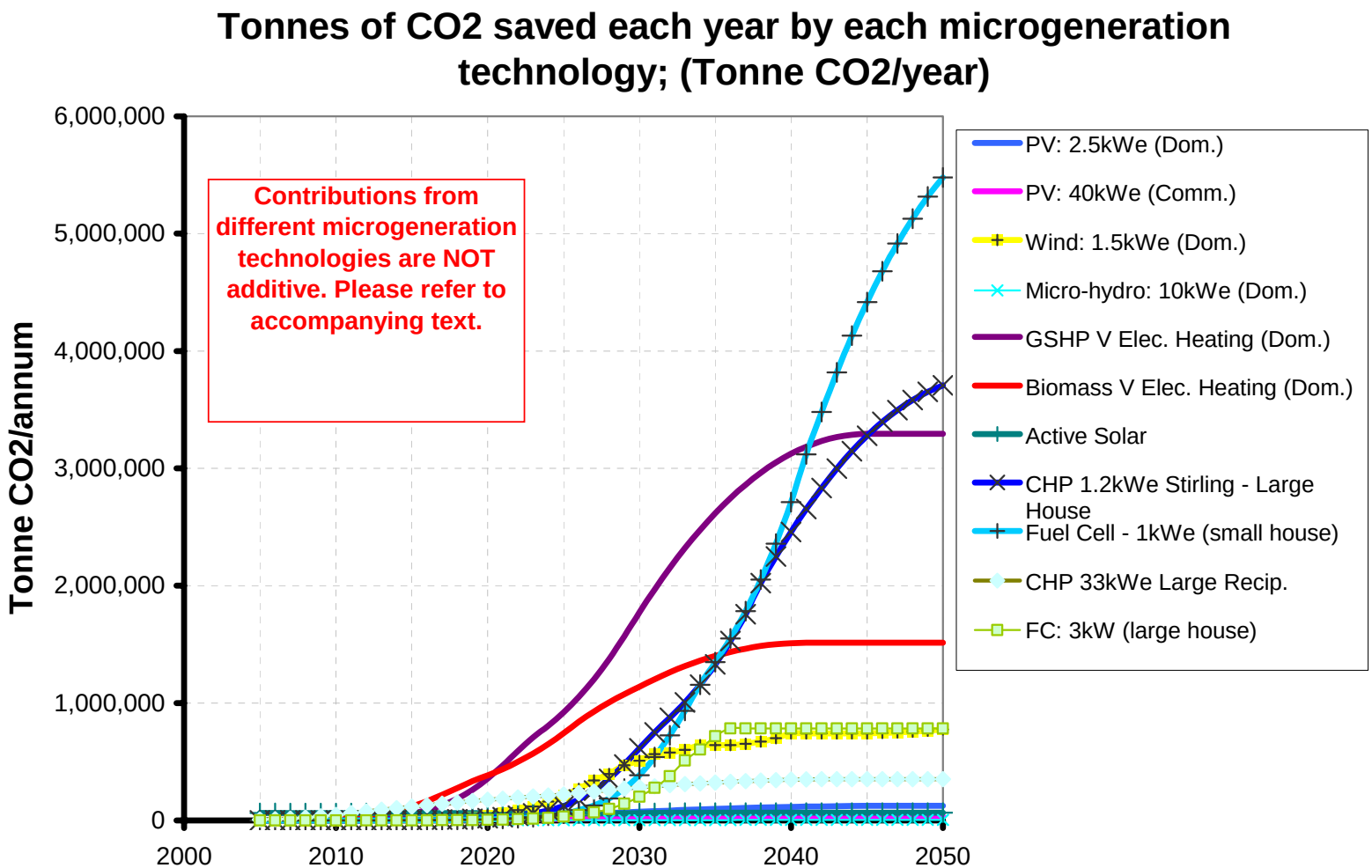
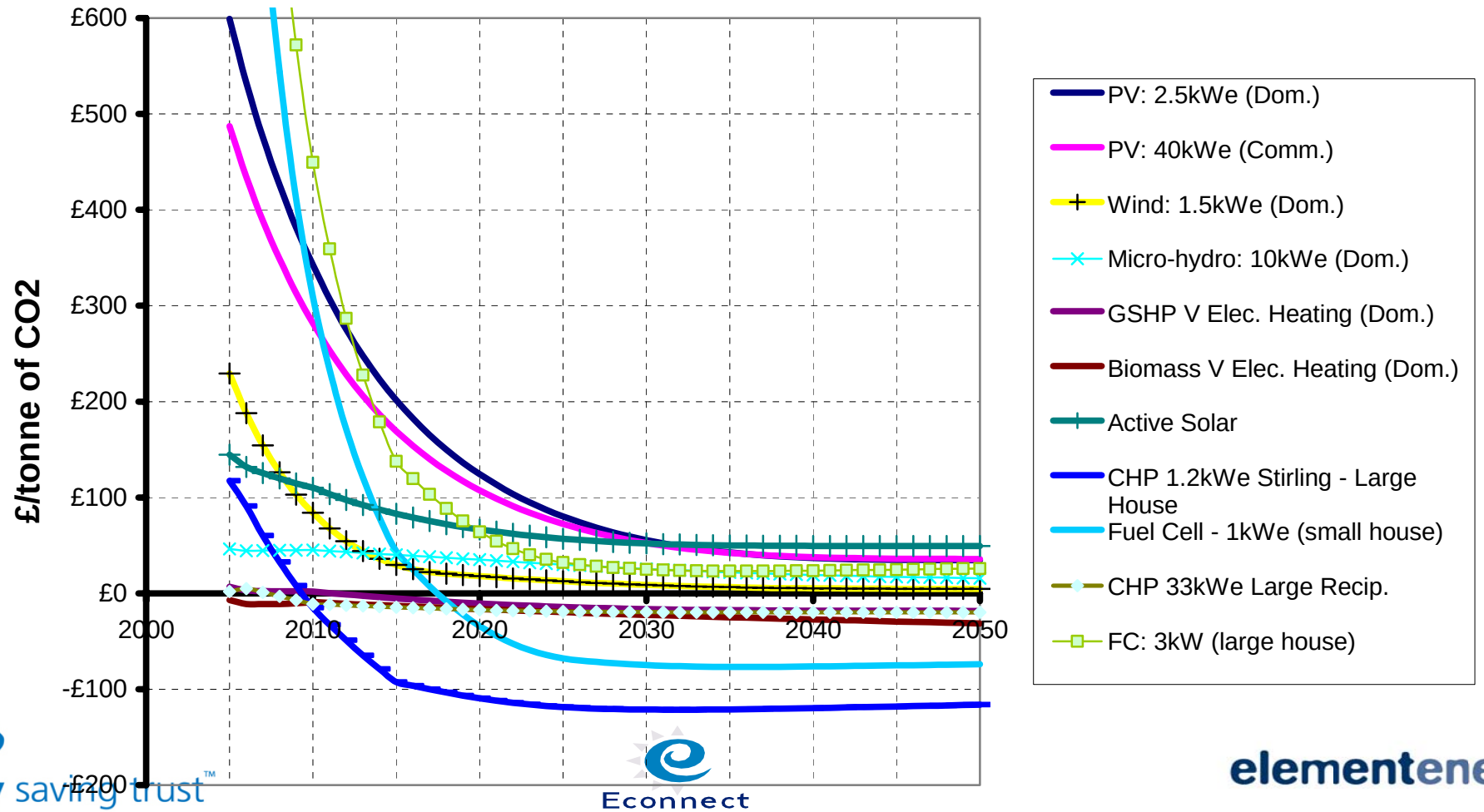
Renewable microgeneration technologies make a significant contribution to avoided CO_2 emissions in the long term even without support.



Renewable microgeneration (both heat and electric) technologies save more CO_2 per kWh than fossil fuel based CHP, therefore there is a disproportionately greater saving relative to number of units installed.

Long term, most technologies could deliver CO_2 reductions at a cost below £50/tonne, with many producing free savings.

£ per tonne of CO2 saved for each technology - HMG standard - Calculated as NPV of energy generation cost minus energy sale value (unsubsidised), divided by total lifetime CO2.



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With projected cost reductions, CHP, renewable heat and small wind can all provide CO_2 saving at no on-cost.

Currently the least expensive CO_2 saving is provided by renewable heat competing with electric heating, where CO_2 saving is essentially free (relative to the incumbent). Large CHP technologies can achieve costs below £50/tonne.

The developing technologies of PV, fuel cells and small wind currently save CO_2 at a cost of well over £100/tonne of CO_2.

However, with projected cost reductions, carbon savings for all technologies fall below £50/tonne by 2050.

Stirling engines are projected to produce savings at no cost (relative to the incumbent) from 2010, with small fuel cell CHP from 2018.

Micro wind tends toward cost neutral CO_2 saving by 2050.

Contents

The model is also able to simulate the effect of different government intervention schemes on technology uptake.

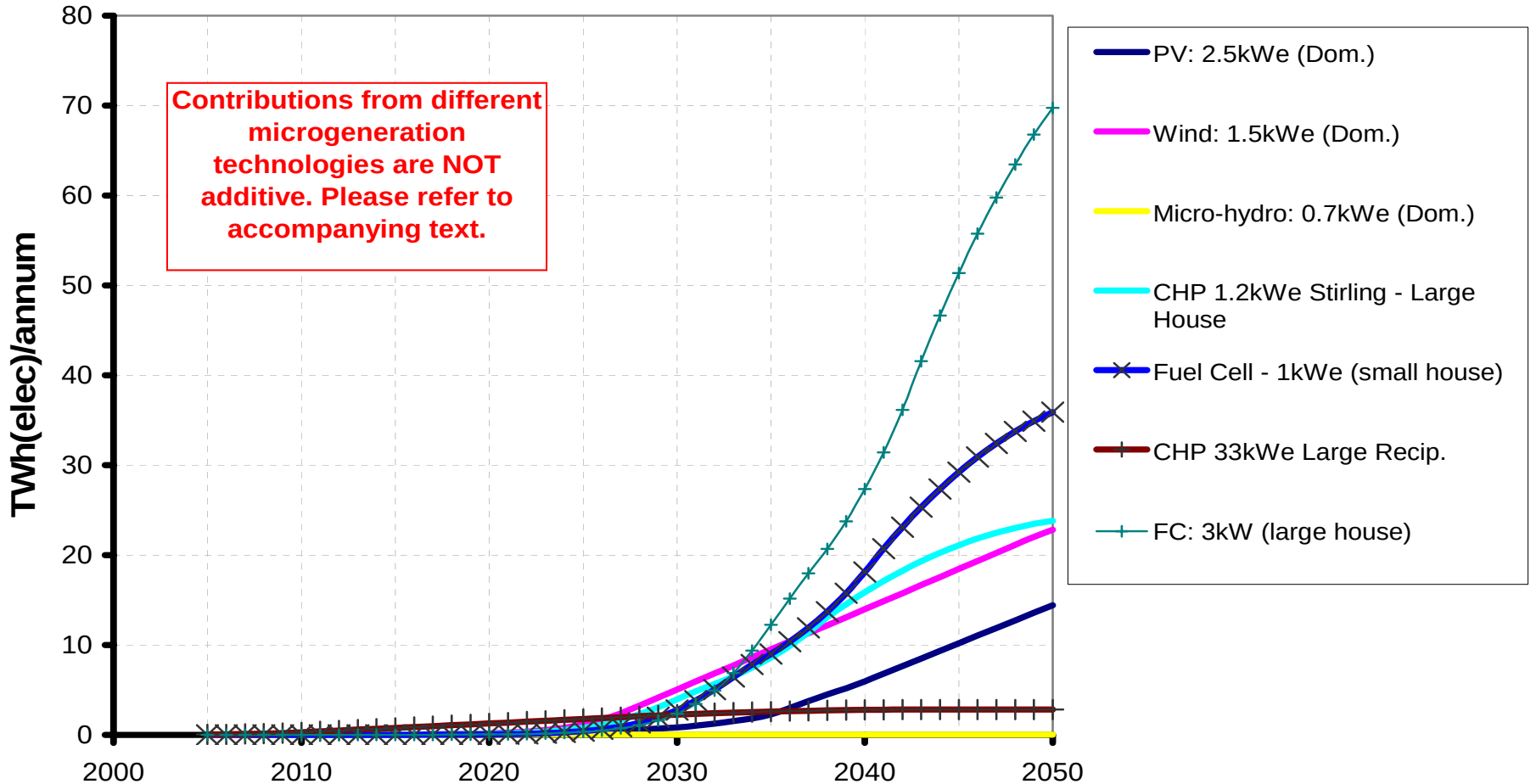
A range of different support schemes have been simulated:

- *Base case (modelled above, section 3.2)* – No government intervention, exported electricity valued at current export price (which is much lower than import price).
- *Energy Export Equivalence (EEE)* – Excess electricity is sold to the grid at a value which is equivalent to electricity imported from the grid.
- *Capital subsidy of 25%* - A government subsidy reduces the capital cost of the technology by 25%. This is provided until the technology achieves cost equivalence with incumbent energy supplies. As the technology cost decreases, the capital subsidy is reduced proportionally, maintaining the cost multiple at a value of one.
- *Access to ROCs* – All electricity from microgeneration has access to the ROC's scheme until 2020**.
- *Microgeneration heat & electricity is eligible for support under EEC****.
- *Regulation affecting 10% of new build:* (i.e. 17,500 installations per year) – This enforces the purchase of the technology* once the energy cost from each technology is the same as the incumbent energy supply (i.e. the technology is cost effective).
- *Regulation affecting all new build:* (i.e. 175,000 installations per year) – as above, but affecting all new build schemes.

(*) Based on typical requirement for subsidy (e.g. condensing boiler program).
(**) Currently renewable microgeneration is eligible for ROCs but transaction costs generally preclude their use; CHP electricity is not ROC eligible.
(***) Currently only the CHP technologies, GSHP and solar water heating are eligible.

With EEE, uptake of PV, wind and large fuel cells is greatly increased. The effect on other CHP technologies is more limited.

Electrical energy generated per year by each microgeneration technology - with Energy Export Equivalence



In this case total microgeneration electricity output exceeds current domestic sector consumption well before 2050

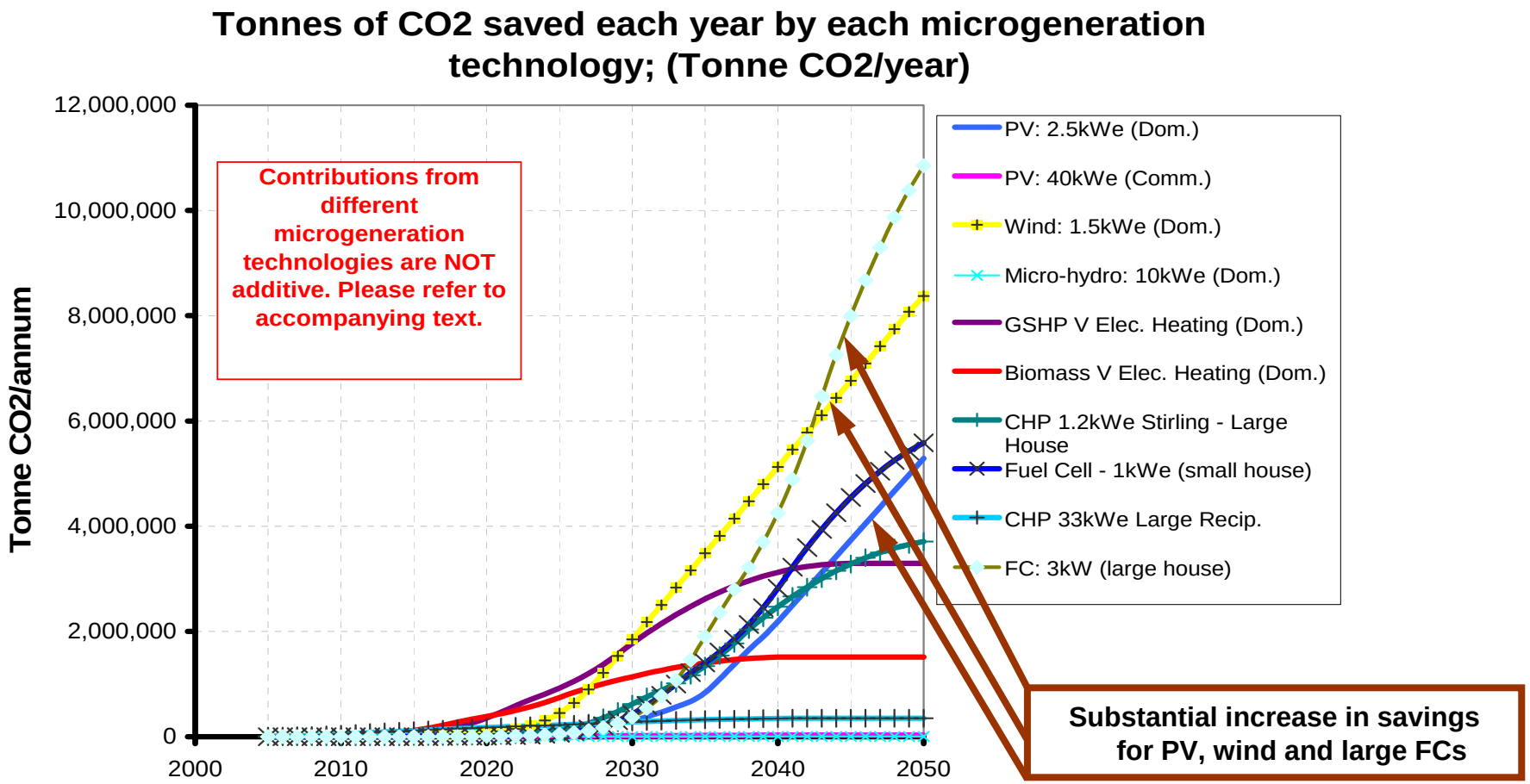
Without EEE, a number of technologies fall far short of their potential to provide UK electricity generation.

The table below illustrates the fraction of total UK electricity generation (2005) which could be provided by micro-generation with and without an EEE type scheme (n.b. data is not additive).

	PV: 2.5kWe (Dom.)	Wind: 1.5kWe (Dom.)	Micro-hydro: 0.7kWe (Dom.)	CHP 1.2kWe Stirling - Large House	Fuel Cell - 1kWe (small house)	CHP 33kWe Large Recip.	FC: 3kW (large house)
Without EEE							
2010	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%
2030	0.1%	0.4%	0.0%	1.0%	0.7%	0.6%	0.3%
2050	**0.1%**	**0.6%**	0.0%	6.3%	9.3%	0.7%	**1.3%**
With EEE							
2010	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%
2030	0.2%	1.3%	0.0%	1.0%	0.7%	0.6%	0.6%
2050	**3.8%**	**6.0%**	0.0%	6.3%	9.4%	0.7%	**18.4%**

The table illustrates the substantial effect the EEE scheme will have on the uptake of three key technologies of small wind, PV and large fuel cells. Each of these technologies export over half of their annual electricity production and so require a good value for electricity exports to make a reasonable economic case for their installation.

EEE will have a major impact on CO_2 emissions, by assisting with higher electricity export from fuel cells and renewable electricity.



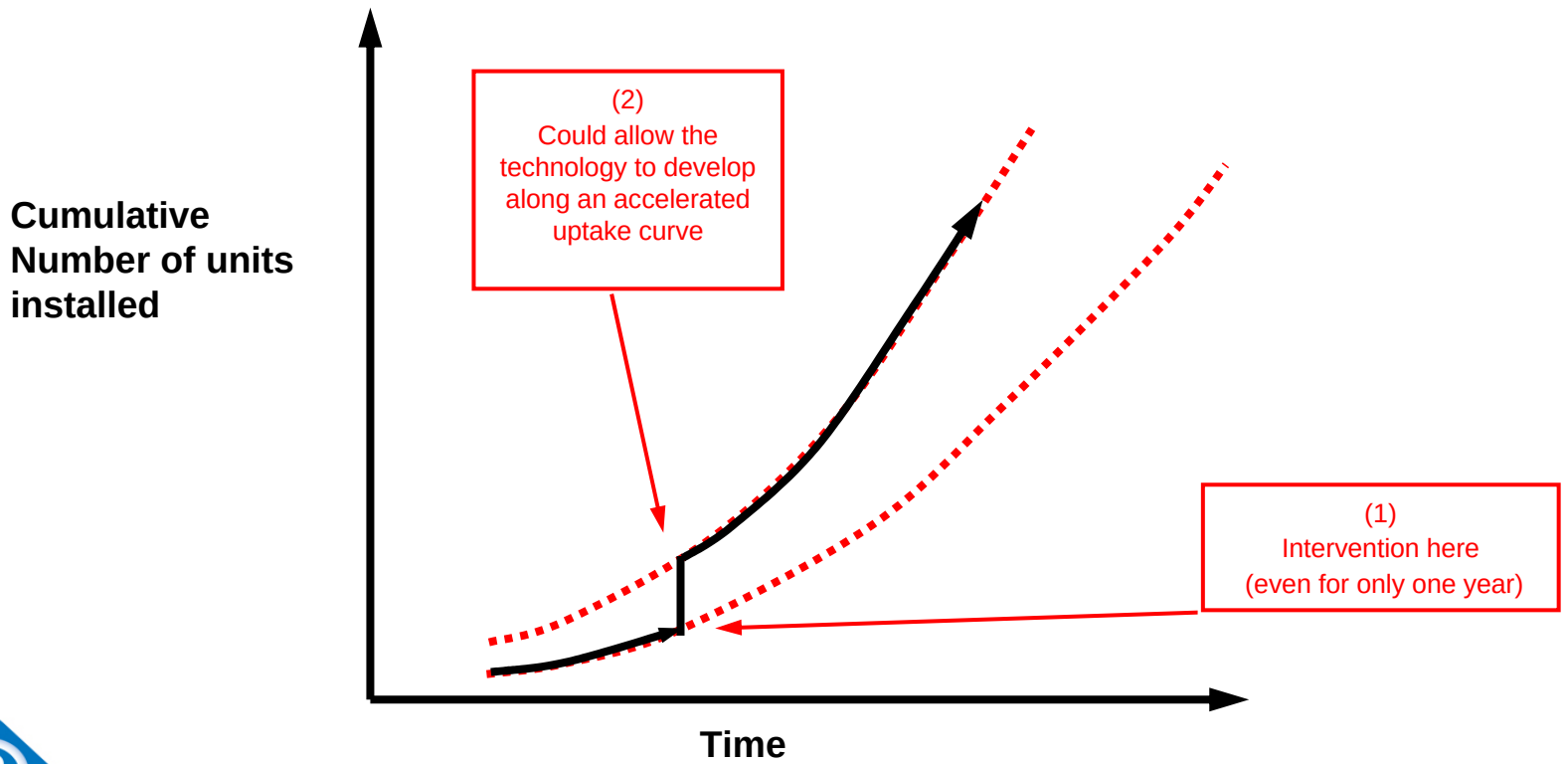
RES based microgen offers the highest CO_2 saving per kWh, but due to its intermittent nature has the largest export fraction – small wind up to 60%. Therefore an EEE scheme or similar valuing of exported electricity is key to achieving the potential emissions cuts.

Appropriate regulation, enforcing installation of cost effective microgeneration technologies will accelerate mass market introduction.

Regulation can enforce sales of new microgeneration technologies, for example by inclusion in the building regulations (as with condensing boilers).

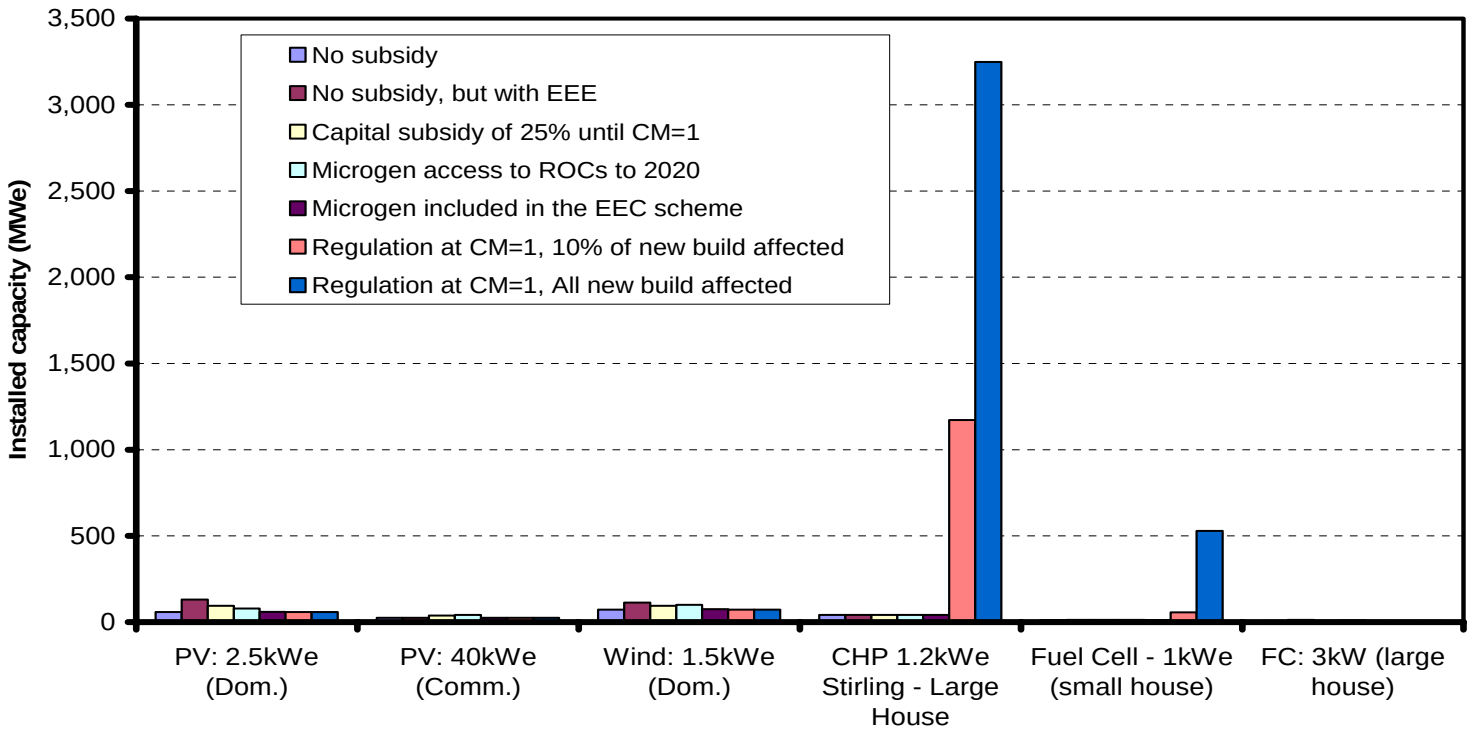
This has the effect of accelerating the move from niche to mass market, by rapidly growing the installed capacity and so overcoming the slow response of consumers to price signals and lack of information.

A similar effect would be observed for a rollout program by utilities, which essentially guarantees a fixed number of installations over a given time period.



To ensure substantial take up of cost-effective technologies by 2020, capital grant aid and regulation is required.

Cumulative installed electrical capacity for each microgeneration technology under a variety of subsidy schemes (in 2020).



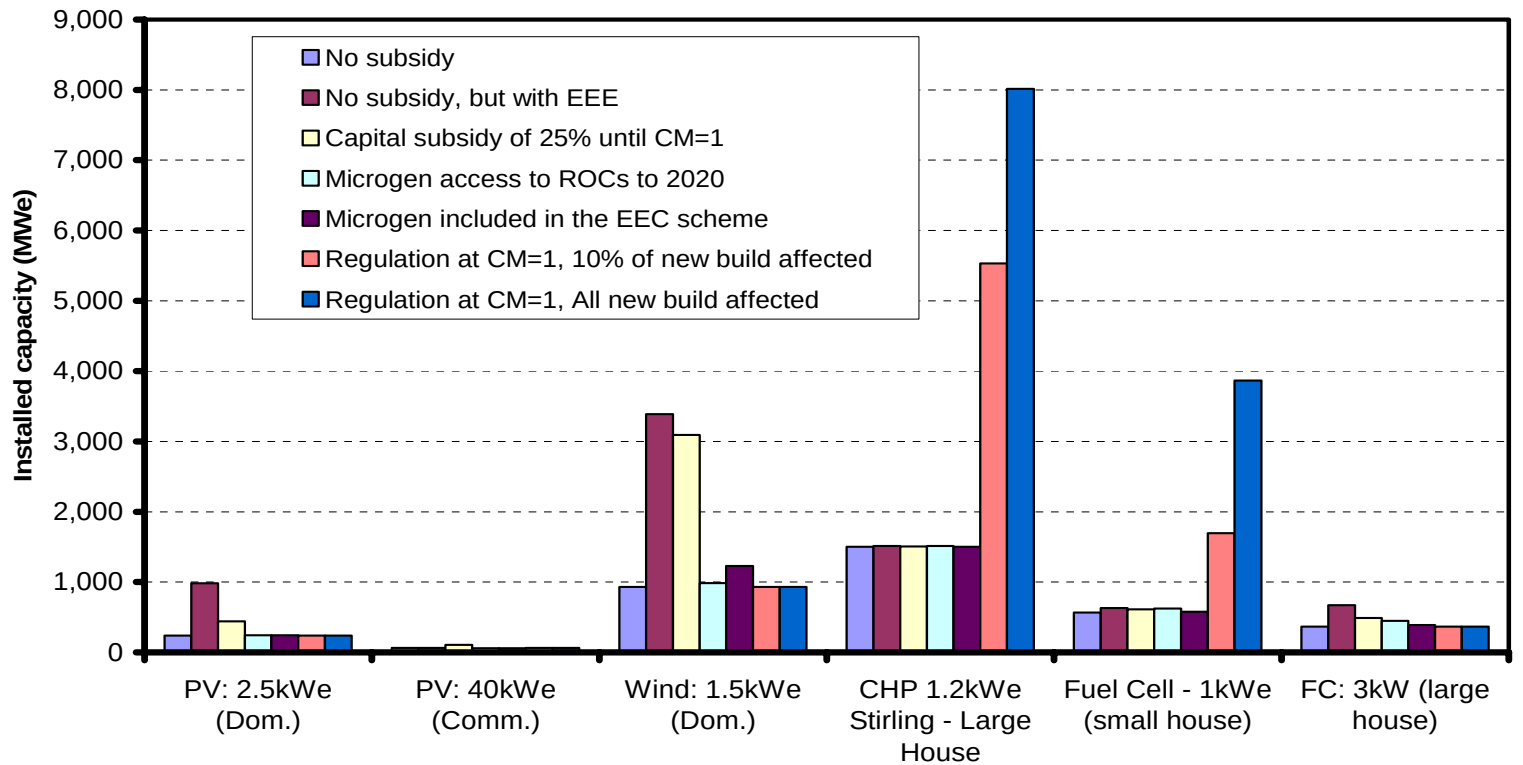
The graph above illustrates that, in the near term, the most effective "intervention" is timely regulation - the greatest mass market effect is achieved by regulation to enforce sales as technologies become cost effective.

If regulation affected all domestic buildings, the 2020 capacity of Stirling engines could be 16GW (20% of UK capacity) and for domestic fuel cells 6.5GW (8% of UK capacity).

*Effects of EEC modelled as a price incentive rather than a quantity obligation

By 2030, capital grants and EEE have the most significant effect on the uptake of small wind systems.

Cumulative installed electrical capacity for each microgeneration technology under a variety of subsidy schemes (in 2030).



With the exception of wind, 25% capital grants have a limited effect on eventual mass market uptake.

However grants are needed to support near term (2005+) development of the market, as few of these technologies are cost effective now. These are required until the technology becomes cost effective.

Neither ROC's alone nor EEC are as effective as EEE in promoting uptake. EEE is vital to renewables in particular.

Summary of main government intervention conclusions

In the near term, nearly all microgeneration technologies require funding to bridge the gap to economic viability. But certain technologies are close to achieving cost-competitive commercial introduction.

Capital grants have the most leverage in boosting the uptake of technologies with rapid cost reduction potential (e.g. micro-wind and micro-CHP). Some technologies (PV) are likely to require substantial capital grants (50%) or similar incentives long-term to sustain uptake.

In the medium to long term, mass-market introduction of microgeneration is best stimulated by:

- increasing the value of exported electricity generation (e.g. EEE and ROC's) (pages 83 and 88).
- timely and cost effective regulation to enforce sales, e.g. via Building Regulations or energy supplier obligations.

In order to stimulate uptake of microgeneration with high electrical export (wind, photovoltaics and oversized fuel cell CHP), *it is essential that the current price distortion leading to low valuation of exported electricity, is corrected*. Without valuing exported electricity at a higher rate it is likely all three technologies will fall well short of their potential deployment by 2050.

Micro-CHP and fuel cell technologies should produce cost competitive heat and electricity by 2010-2020. *Their uptake is best stimulated by using regulation* to accelerate the transition from a niche to a mass market product. Regulation need only occur when the technology is cost effective (e.g. inclusion as a requirement in building regulations, as with condensing boilers, or within a supplier obligation).

Likewise renewable heating technologies (biomass and GSHP in rural/semi-rural areas) can already provide lower cost heat than those based on LPG or electricity.

Contents

The model is also affected by assumptions regarding consumer behaviour.

The "baseline" population behaviour model has the following aspects

- Capital is valued with an interest rate of 8%.
- Loan lengths are equivalent to equipment lifetimes.
- While a small but important percentage of the population is willing to accept higher cost multiples (CM), for most of the population a purchase will not be made until CM =1 (i.e. cost equivalence is reached).
- With CM = 1, the average consumer does not place a premium on the environmental benefit of these technologies; neither do they invest to make a profit (they break even).
- Experience with certain domestic energy technologies (such as condensing boilers and compact florescent light bulbs) has shown that consumers may not invest, even when the technology is cost effective (and the cost multiple is less than unity).
- In addition, some anecdotal evidence suggests residential consumers might also have a maximum capital investment threshold of 500 pounds, combined with an acceptable payback period of 3 to 5 years.
- Therefore, a **range of consumer behaviour "models"** are required to simulate possible future behaviours.

A range of different consumer behaviour models have been considered.

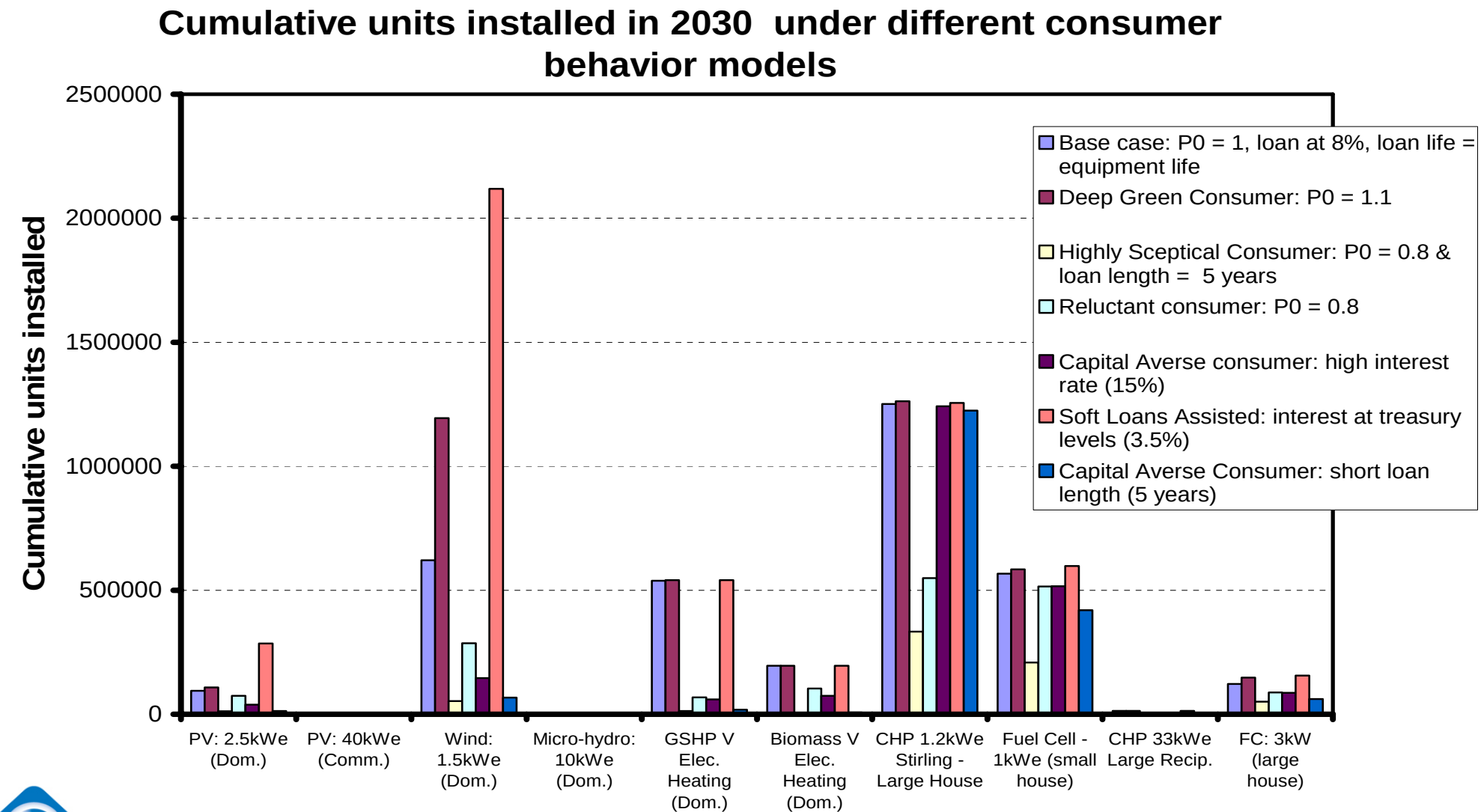
A series of alternative consumer attitudes to energy investments have been developed and can be simulated as a part of the uptake model:

- Base Case: Described above (investments at CM=1, 8% interest rate over the life of the equipment).
- Reluctant Consumer: Significant investments occur only when CM reaches 0.8 (i.e. P0=0.8)
- Capital Averse Consumer: Interest rate = 15%
- Capital Averse Consumer: Loan length = 5 years
- Highly Sceptical Consumer: Critical CM (P0) = 0.8 and loan length = 5 years
- Soft Loan Assisted Consumer: Interest rate = 3.5%
- Deep Green Consumer: Significant investment occurs when CM reaches 1.1

The choice of consumer behaviour assumed has a profound effect on the model outputs.

The type of consumer will be affected by the overall national policy towards the 'soft barriers' affecting microgeneration. For example the consumer approach to the cost multiple (CM) at which they will elect to deploy a microgeneration technology will depend on the level of education of both consumers and suppliers about the new microgeneration products, combined with their awareness of the environmental benefits of the technology.

There is a wide discrepancy between the uptake of each technology for a 'Green' consumer model and a 'Sceptical' consumer without government intervention.



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Each consumer model affects the uptake of each technology in different ways.

For capital-intensive technologies (specifically wind and PV), consumer attitude to capital has the greatest effect. Soft-loan schemes rapidly increase uptake, whilst high-interest loans and short loan repayment periods have a major adverse effect.

The effect of capital-focussed behaviour is less severe for technologies for whom fuel is a major component of yearly costs (e.g. CHP, biomass, GSHP). Here the greatest effect is the consumer's attitude to the price of delivered energy (i.e. the value of P0). If consumers require a substantial price incentive to switch technologies (i.e. P0 = 0.8 implies 20% cheaper energy), most microgeneration technologies struggle to achieve their maximum impact.

The consumers attitude to price can be affected by government actions, such as clarity regarding which technology is most appropriate for adoption, as publicity.

Capital issues:- Consumers wary of high capital costs can be assisted through the provision of long term low cost loans. Alternatively, utilities or purpose-built ESCO's can be required to bear the long term capital investment costs of the new technologies, as these private organisations can structure a business plan around access to loan finance.

Consumer approach to cost:- consumers will require substantial education and awareness raising to ensure a shift to microgeneration technologies even at cost equivalence with conventional energy supply. Alternatively regulation can be used to enforce consumer behaviour.

Contents

Assessment by technology (1).

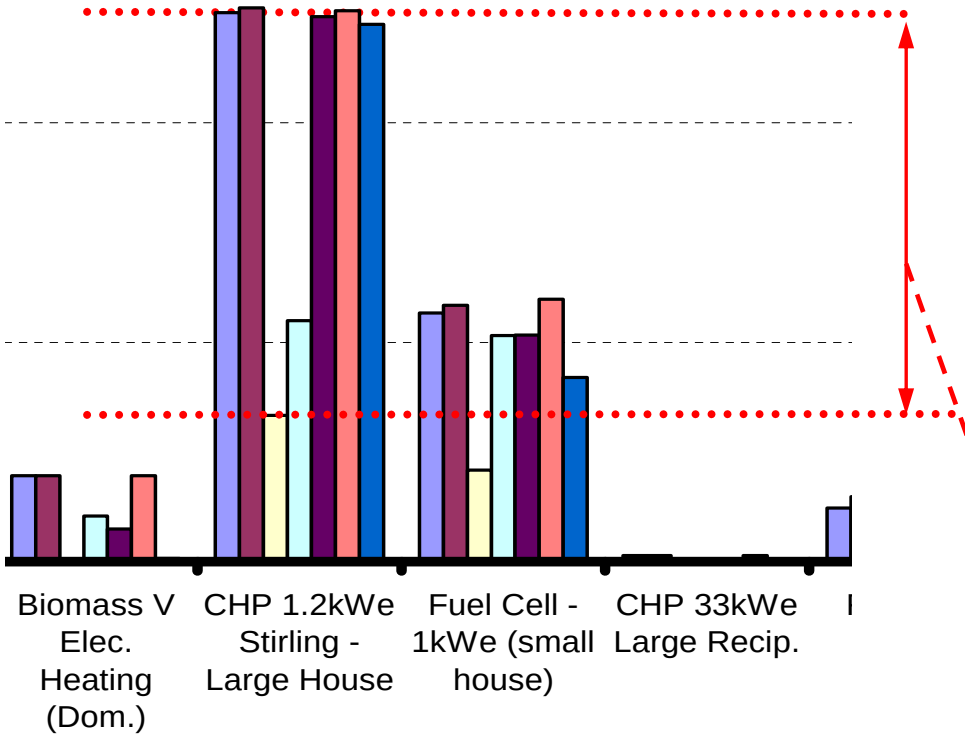
The following pages assess the performance of each technology under different support schemes. The table below summarises the results.

	Maximum 2050 potential assuming optimum support	Becomes competitive with conventional energy by	Short term intervention required to achieve maximum potential	Long term intervention required to achieve maximum potential
PV	> 20 GWe	2049	Substantial subsidy program continued and EEE	Continued subsidy support to 2030, requires EEE + removal of soft barriers to uptake, especially access to low cost capital
Wind	15 GWe	2015	Requires EEE to achieve substantial penetration, short term subsidy support to prepare the market, removal of unnecessary planning barriers	Action to remove soft barriers, notably allowing access to low cost capital, consumer education and reduction in planning barriers
Stirling/small recip CHP	9 GWe	2010	Likely to be most relevant to retrofit existing dwellings. Uptake is best accelerated through regulation to enforce uptake (e.g. building regs or supplier obligations). Also requires removal of soft barriers, especially education of consumers to ensure uptake once the technology is cost competitive.	Achieving long term potential requires removal of soft barriers to uptake - educating and/or forcing consumers to take up the technology once cost equivalence is reached
Fuel cell CHP - 1 kWe for small heat loads	8 GWe	2017	Likely to be most relevant to new build. Again, best accelerated through regulation. Soft consumer barriers must be removed for maximum uptake	Long term market should saturate provided consumers/installers are educated to select lowest lifecycle cost products.

Assessment by technology (2).

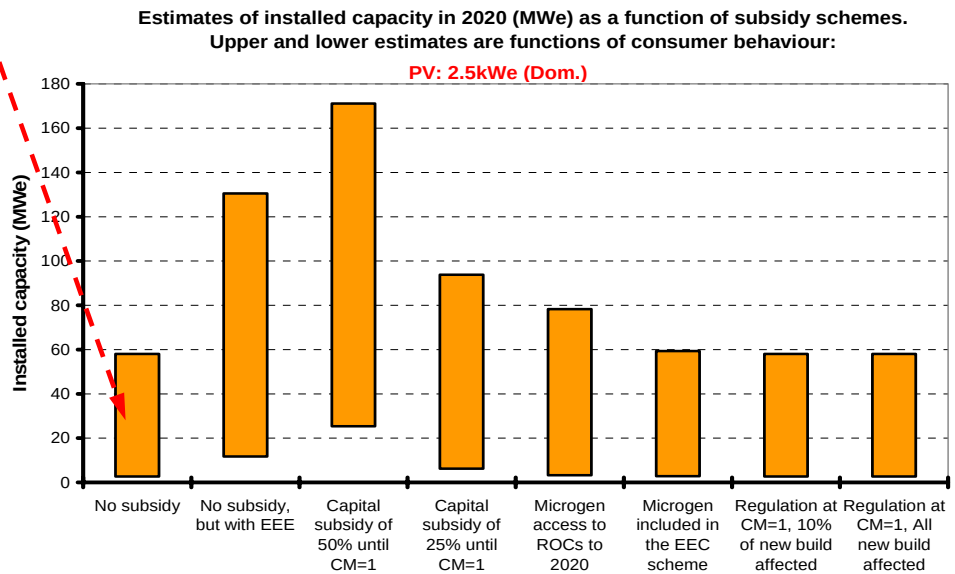
	Maximum 2050 potential assuming optimum support	Becomes competitive with conventional energy by (date)	Short term intervention required to achieve maximum potential	Long term intervention required to achieve maximum potential
Oversized fuel cell CHP - 3 kWe	20 GWe	2020 - assuming EEE, otherwise 2050	Assumes installation in existing dwellings with large heat demand. Substantial electricity export means this option will only develop if EEE is achieved or a large >50% capital subsidy is provided.	Provided EEE, removal of soft barriers will again be crucial to maximise potential. Likely to be particularly relevant to large utility/ESCO type installation and ownership.
Large recip/small microturbine type CHP	550 MWe	2005 in appropriate buildings (>5,000 hours operation)	The market (leisure, health, residential care etc.) would be substantially stimulated by allowing CHP electricity within the ROCS scheme.	Again the ROCs scheme is the optimum mechanism for ensuring uptake
GSHP	12 TWh of heat annually	2005 vs. electric/LPG heating	Already cost competitive in homes without natural gas or oil heating. Can be encouraged through regulation where electric and LPG are the other options. Increased consumer awareness, and education of installers is important	Removal of soft consumer related barriers.
Biomass (sub 100 kWth)	4.5 TWh annually	2005 vs. electric/LPG heating	As for GSHP - can be encouraged through building regs/planning and where biomass supply chains exist	Removal of soft consumer related barriers.
Micro hydro	100 MWe	2050	The market requires either easy access to ROCs or a substantial >50% subsidy scheme.	Removal of soft barriers (e.g. low cost access to capital and improved consumer education will help to ensure uptake in a well supported environment.
Active Solar	6 TWh per year	2050+ (2030 assuming best case tech development)	The market requires substantial subsidy to show any growth above the existing penetration levels, even in competition with electric heating	Subsidy would be required till at least 2030

The base case and sceptical consumer can be used to bound the likely uptake arising from incentive schemes.



The difference between the base case and 'Sceptical consumer' model is considered as the upper and lower bound on uptake.

Achieving the 'upper' bound will depend on the approach to soft barriers, by encouraging consumer uptake through soft loans, energy services, consumer and supplier education and awareness programs



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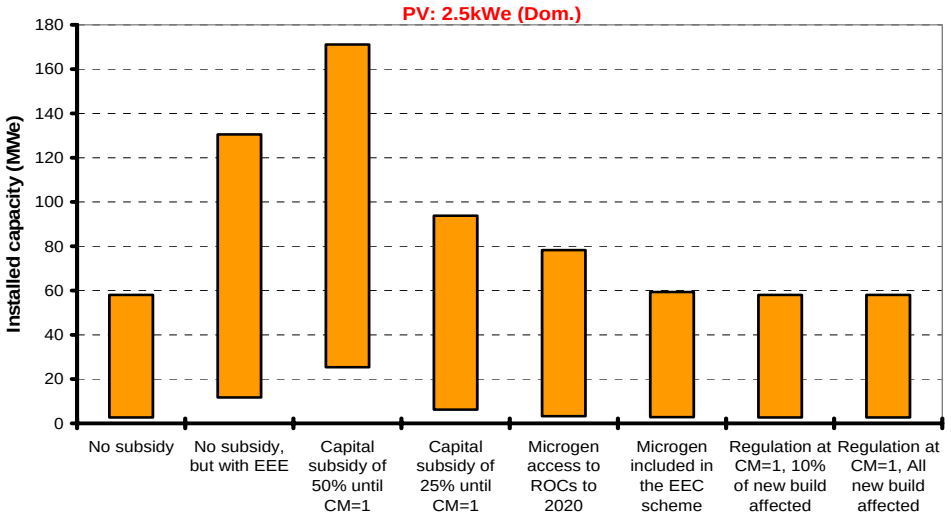
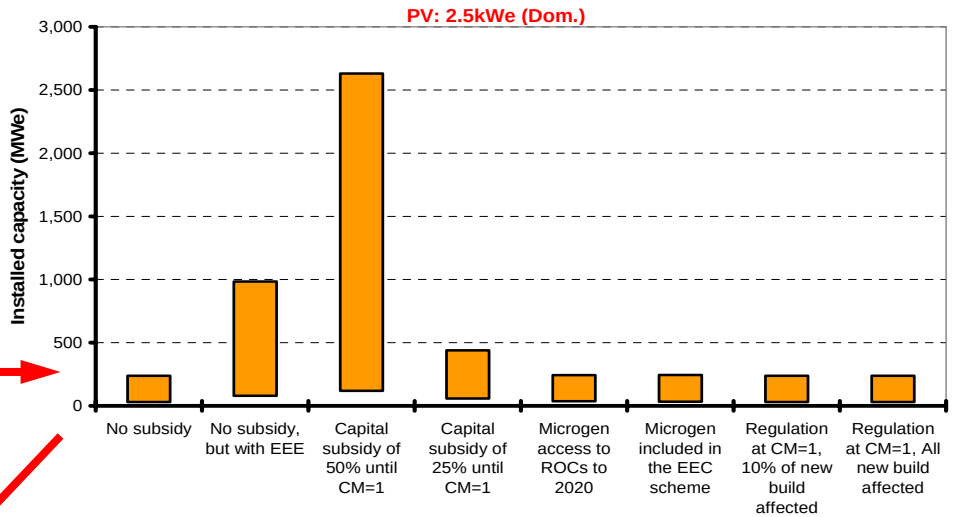
Small PV: Uptake requires significant support to 2030; in the long term EEE pricing is vital to sustain the market.

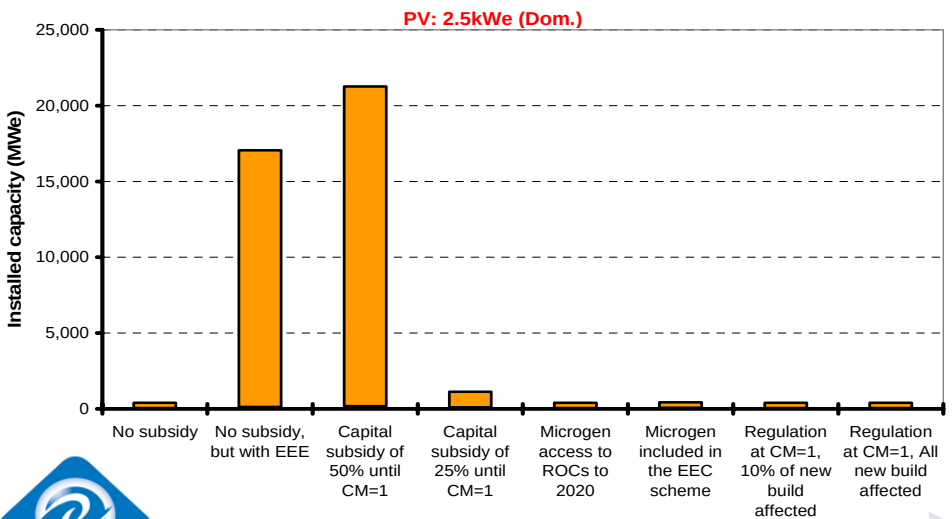
Estimates of installed capacity in 2020 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:



Estimates of installed capacity in 2030 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:



Estimates of installed capacity in 2050 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:



Capital subsidies are required near term to overcome the substantial cost barrier.

Once costs have reduced significantly (by 2030) a higher valuation of exported electricity (EEE) is vital for ongoing viability of PV.

The saturation capacity of domestic PV is the highest of all microgenerators.

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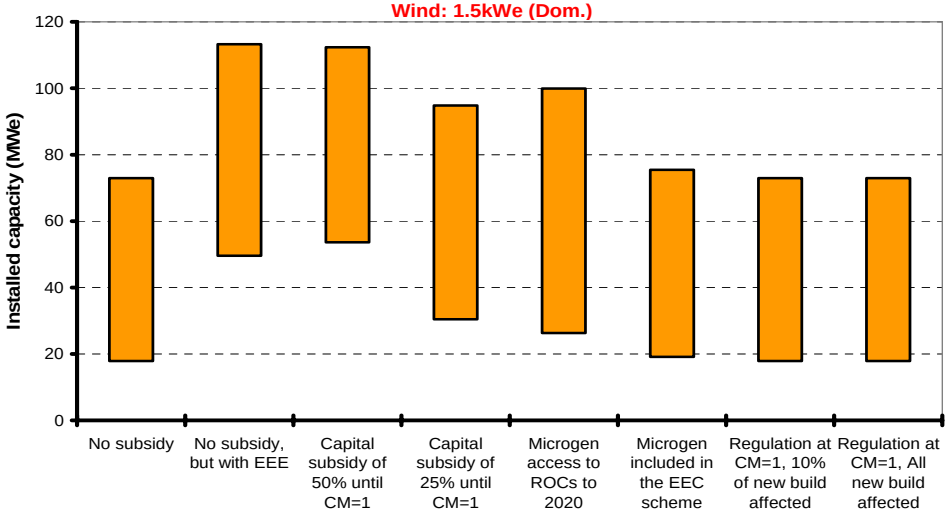
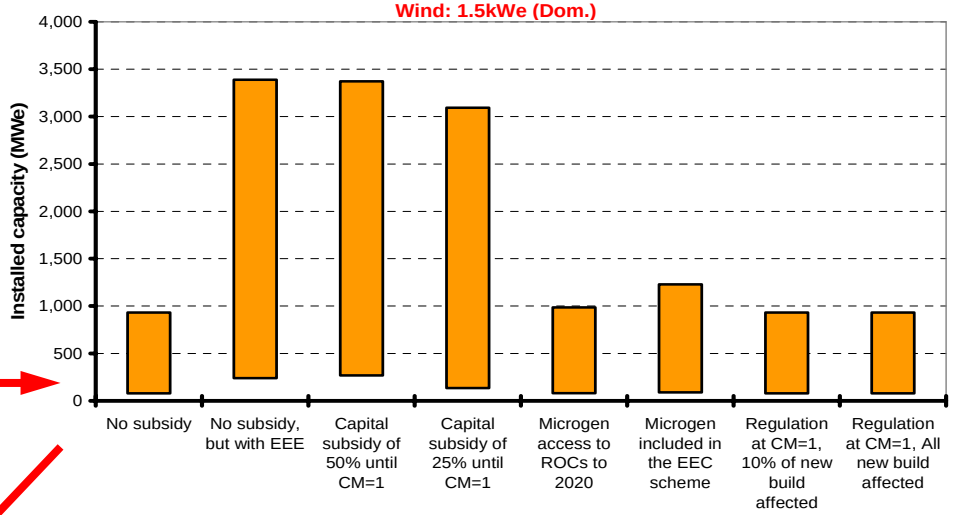
Small wind could reach significant levels by 2030 and saturation by 2050 if EEE (or govt support) is provided.

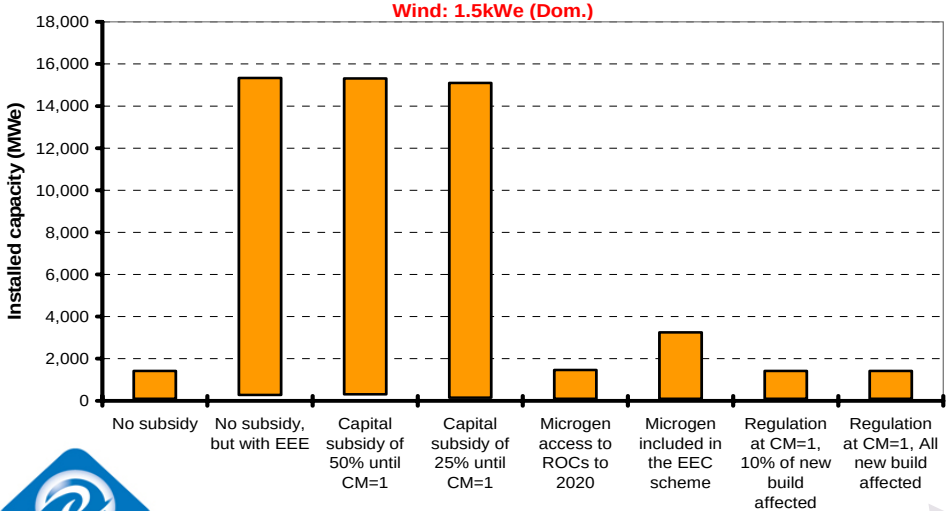
Estimates of installed capacity in 2020 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
Wind: 1.5kWe (Dom.)



Estimates of installed capacity in 2030 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
Wind: 1.5kWe (Dom.)



Estimates of installed capacity in 2050 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
Wind: 1.5kWe (Dom.)



Cost-effectiveness is predicted to occur circa 2015.

While regulation could help in the near term, access to ROC's and/or capital grants could also assist uptake.

In the short term grants are required to encourage uptake and support the market until costs reduce to competitive levels.

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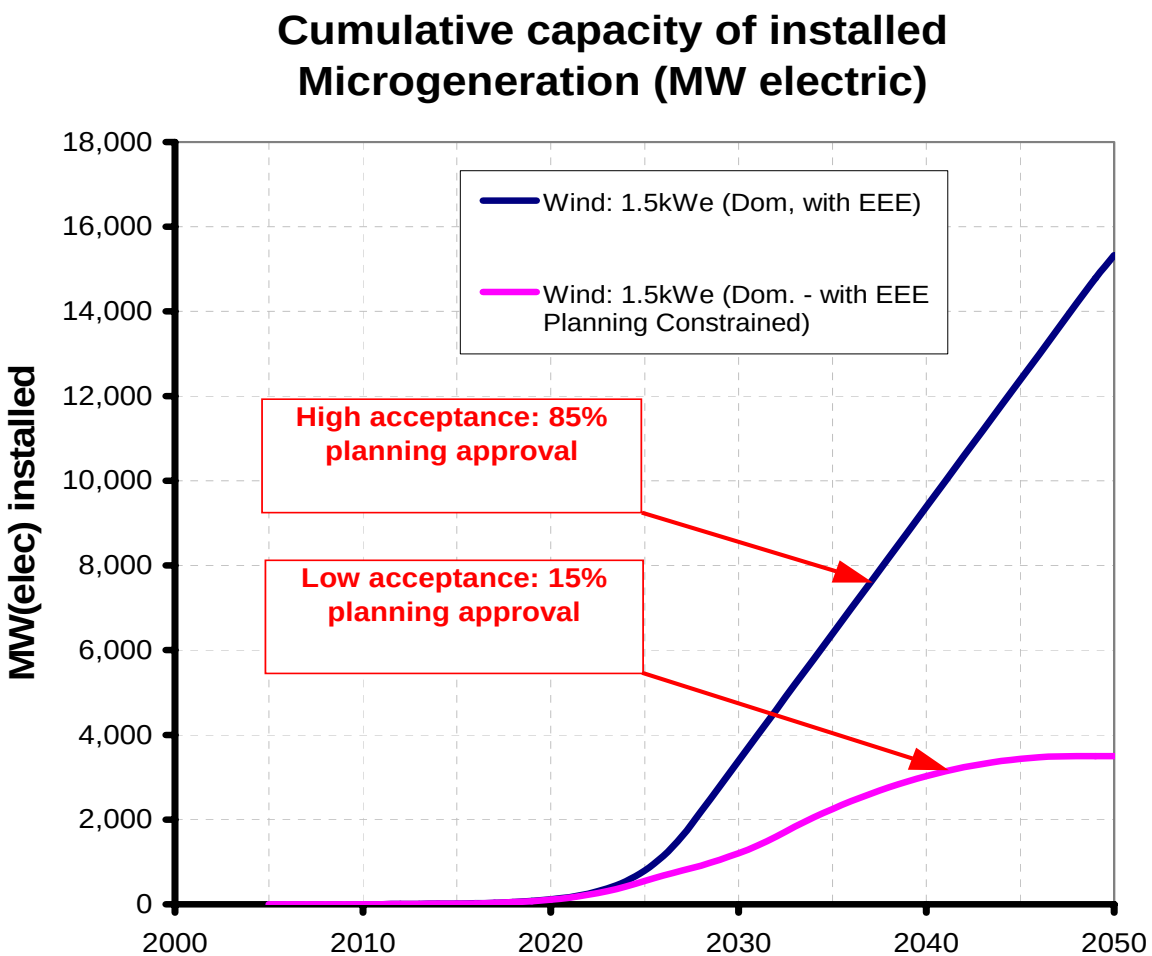
Attitudes to small wind will determine potential planning constraints.



Domestic wind turbines are unusually susceptible to planning problems.

Under a scenario which provides fair valuation of exported energy (EEE) a capacity of circa 20GW could be achieved.

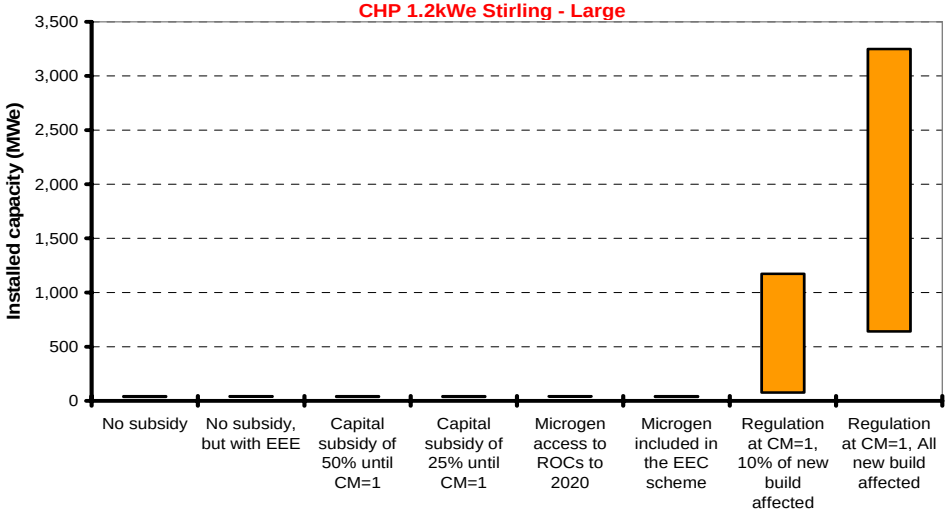
This assumes a high rate of planning acceptance (85%).

If planners reject most domestic wind projects (acceptance rate 15%) the resulting UK domestic wind generating capacity will be much smaller.

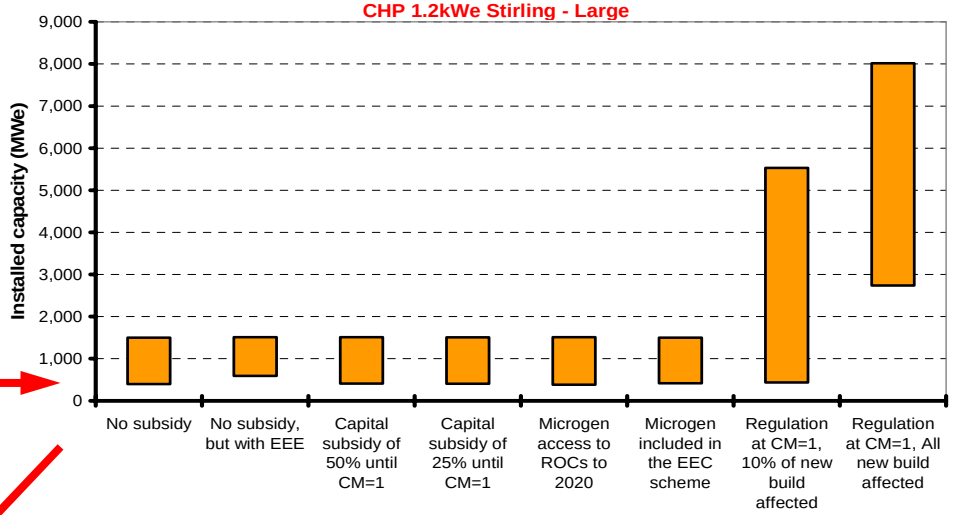
Early action should be taken to answer all reasonable environmental impact concerns in relation to small wind.

Stirling CHP: cost-effective regulation will improve uptake until circa 2020; thereafter it is self-supporting.

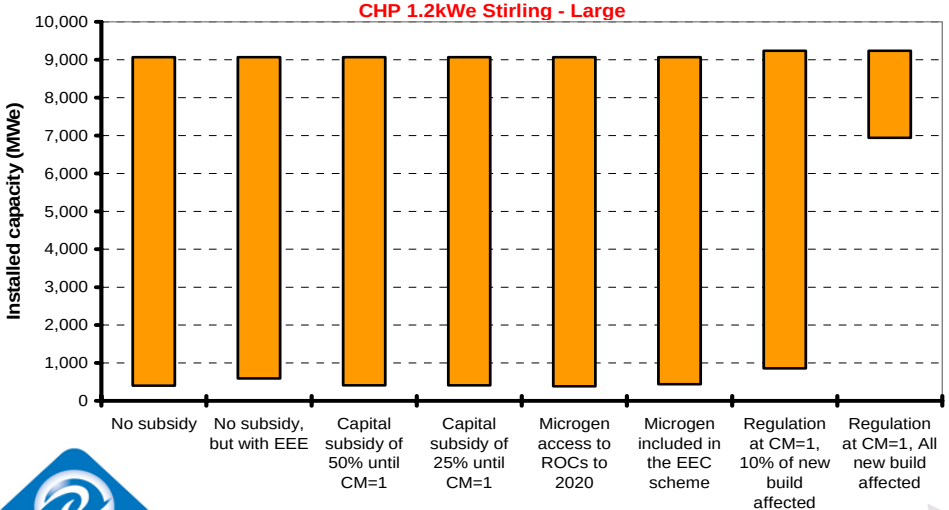
Estimates of installed capacity in 2020 (MWe) as a function of subsidy schemes.
Upper and lower estimates are functions of consumer behaviour:
CHP 1.2kWe Stirling - Large



Estimates of installed capacity in 2030 (MWe) as a function of subsidy schemes.
Upper and lower estimates are functions of consumer behaviour:
CHP 1.2kWe Stirling - Large



Estimates of installed capacity in 2050 (MWe) as a function of subsidy schemes.
Upper and lower estimates are functions of consumer behaviour:
CHP 1.2kWe Stirling - Large



Despite becoming commercial circa 2010, starting from such a low base (number of installations) means that it takes another 10 years to reach GWe installed levels.

Uptake can be guaranteed by regulation to enforce sales (which need only last a few years).

Long term, removal of consumer related soft barriers is critical to ensure uptake.

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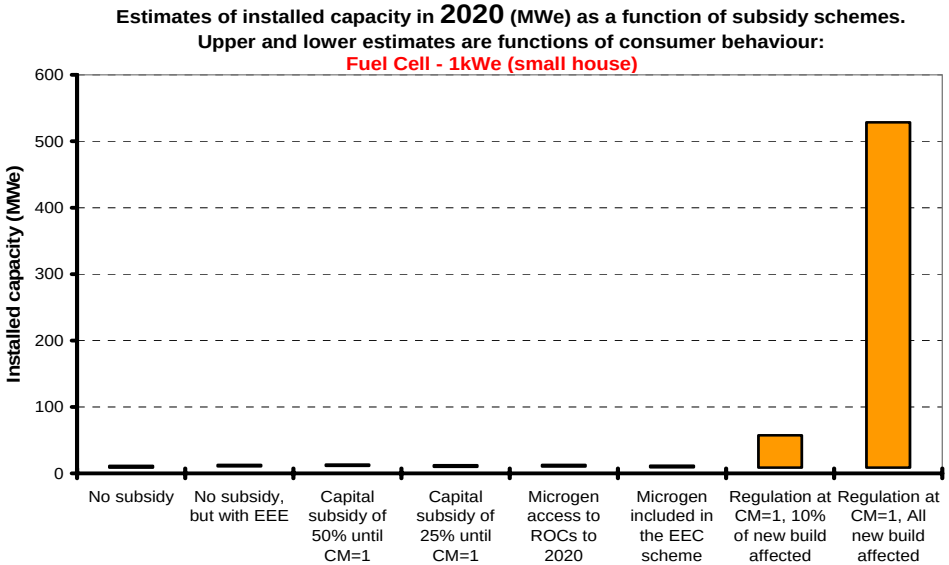
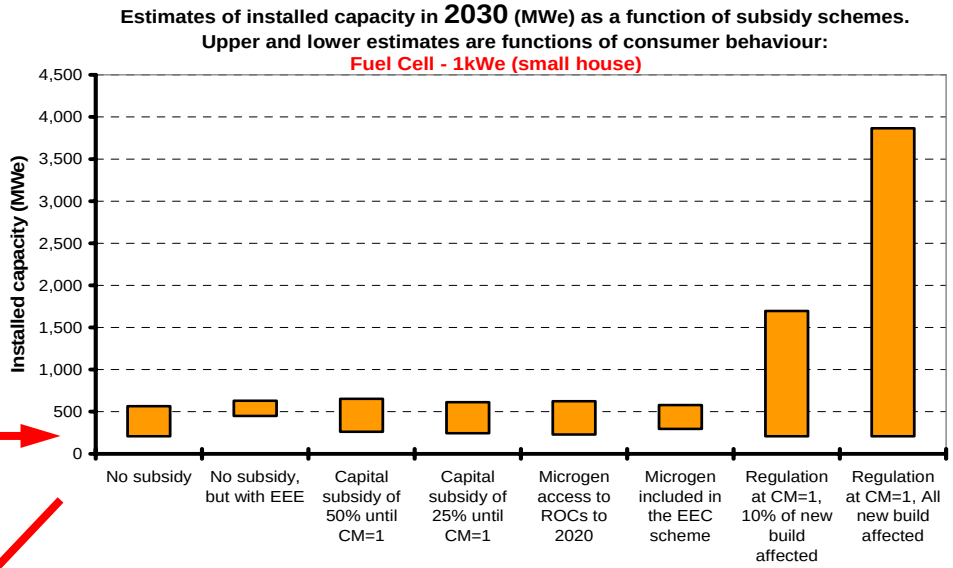
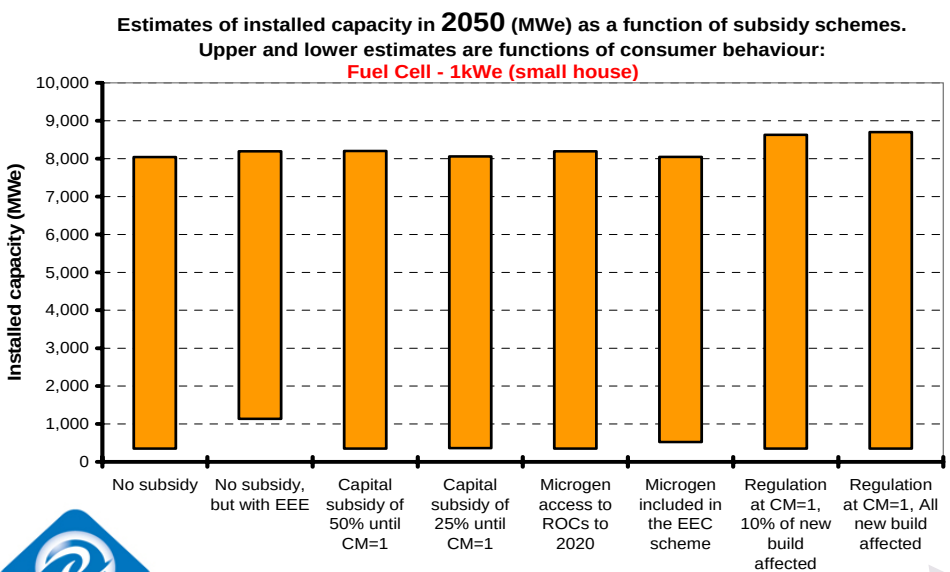
Fuel cell CHP: cost-effective regulation is a near-term priority; in the long term, it will saturate its market.







As with Stirling engines, to enhance uptake once fuel cells become cost effective, regulation or large short-term deployment programmes are needed.

The effect of either of these is to allow the technology to proceed on a much steeper growth curve, once the programme is complete.

Again, removing consumer related soft barriers is key to ensuring uptake meets the potential.

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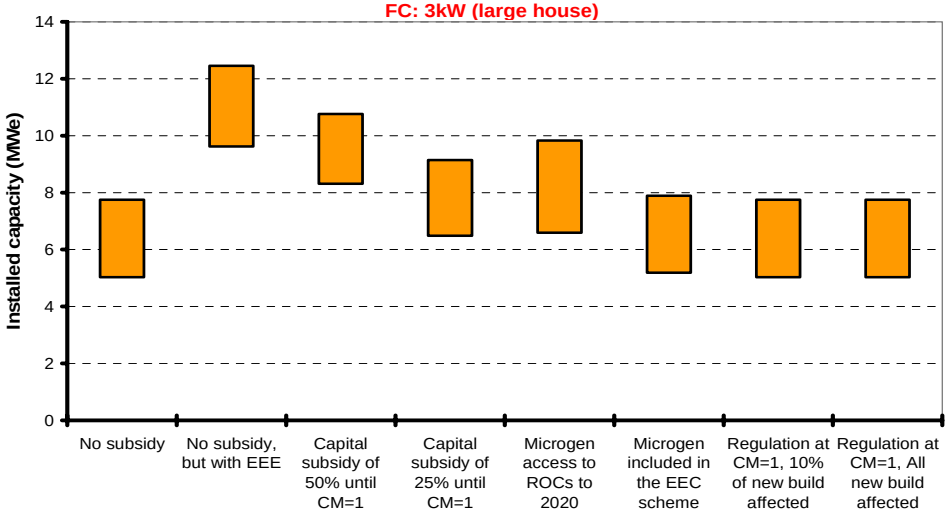
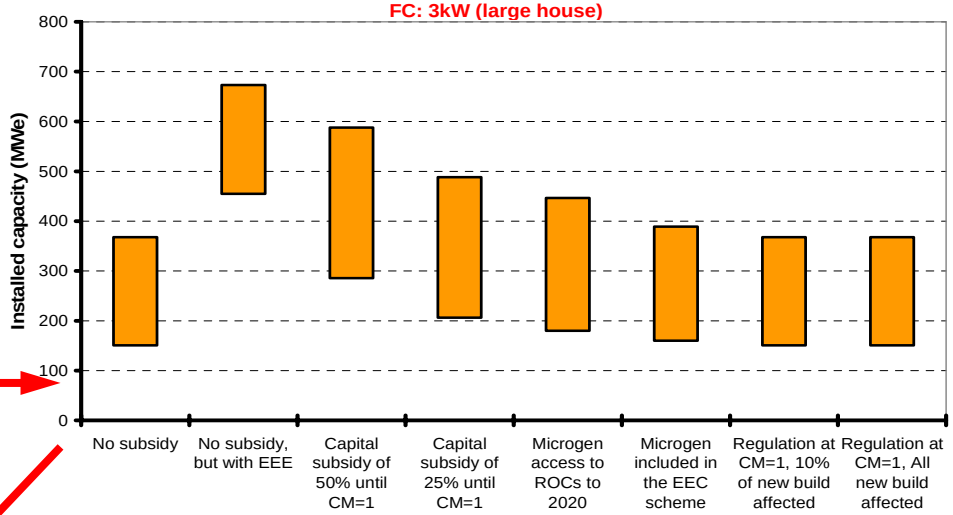
3kWe Fuel Cell CHP: could achieve substantial uptake levels but it is highly dependent on EEE.

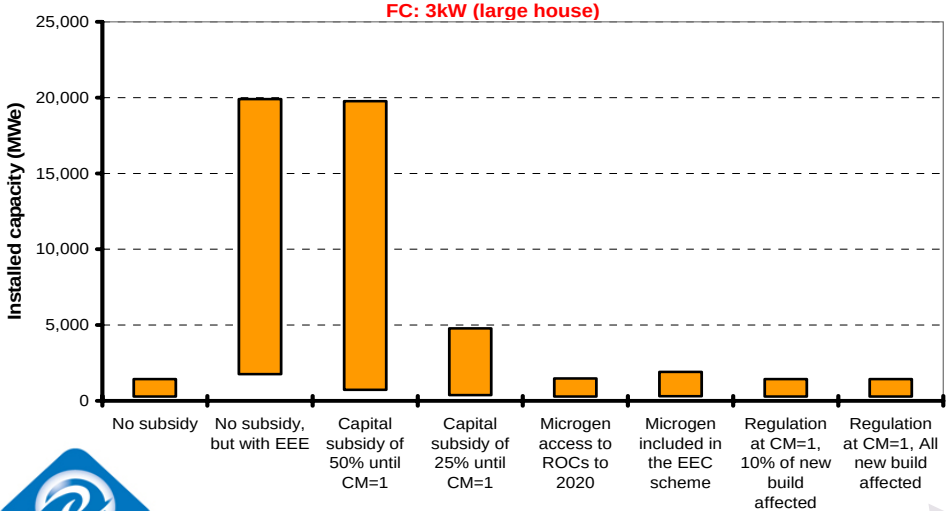
Estimates of installed capacity in 2020 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
FC: 3kW (large house)



Estimates of installed capacity in 2030 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
FC: 3kW (large house)



Estimates of installed capacity in 2050 (MWe) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
FC: 3kW (large house)



This technology is important as it will supply at maximum power during peak loads (in winter) and have a lower output in the summer.

Capital subsidies can help deployment, but it is more important to incentivise this technology (which exports most of its electricity generated) by ensuring EEE.

20 GWe could be achieved by 2050.

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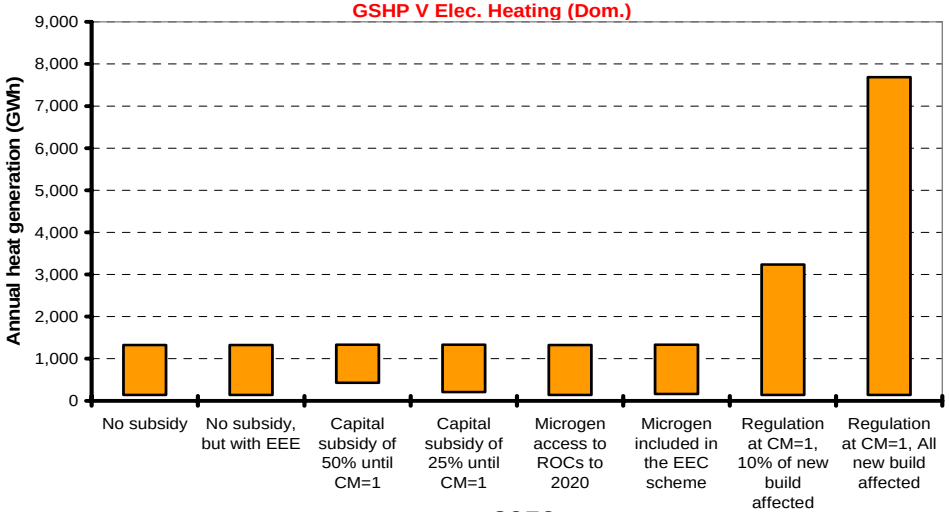
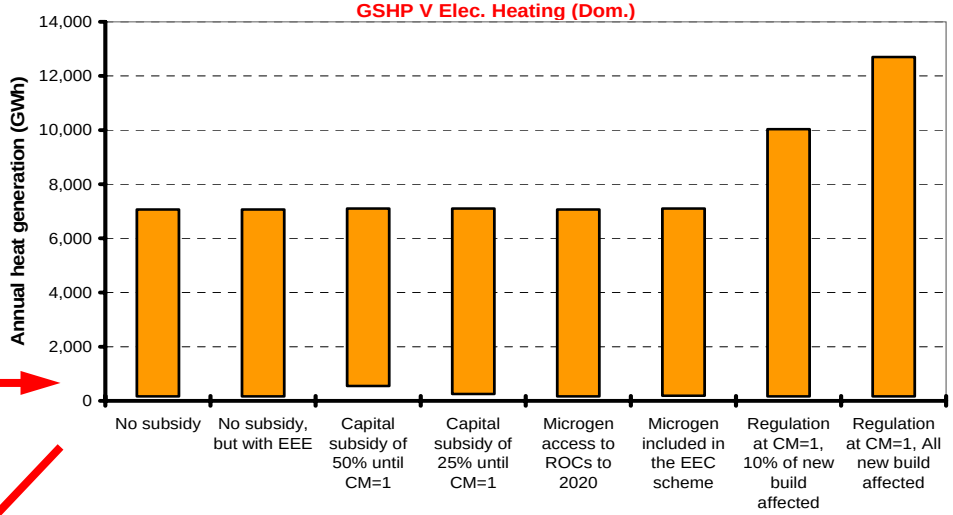
GSHP: Regulation helps in the near-term (to 2020) but thereafter the technology could saturate its target market.

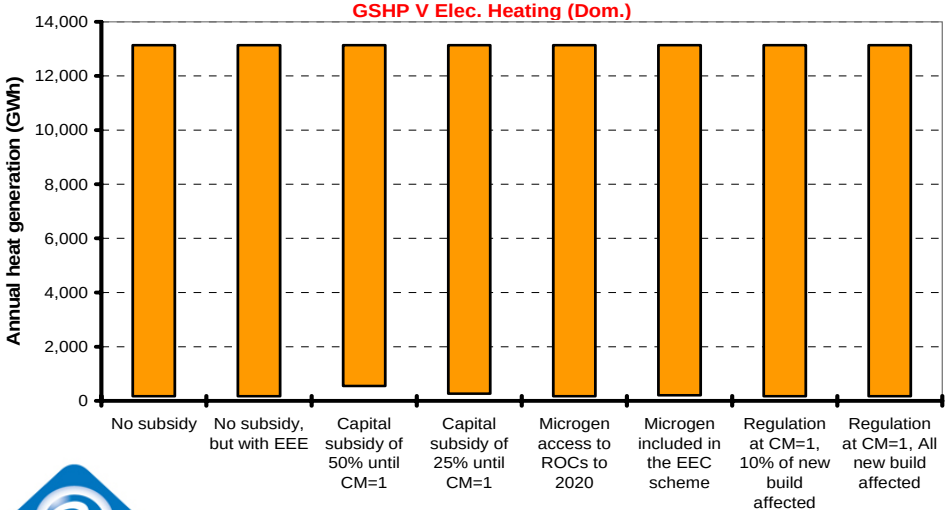
Estimates of annual heat generation in 2020 (GWh|heat) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
GSHP V Elec. Heating (Dom.)



Estimates of annual heat generation in 2030 (GWh|heat) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
GSHP V Elec. Heating (Dom.)



Estimates of annual heat generation in 2050 (GWh|heat) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
GSHP V Elec. Heating (Dom.)



Grant aid shows little effect in this case as GSHP is replacing electric heating.

For GSHP to replace oil or gas heating, subsidies would be required.

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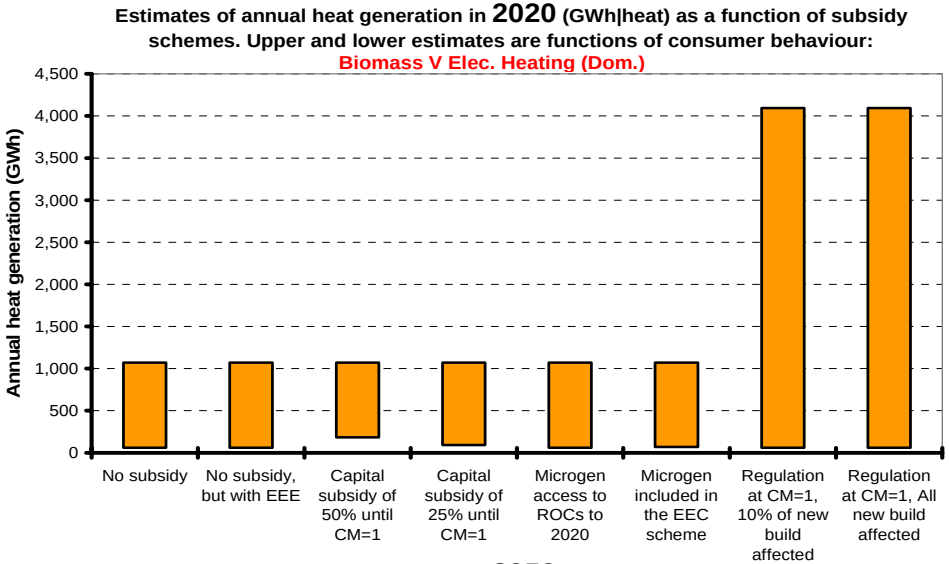
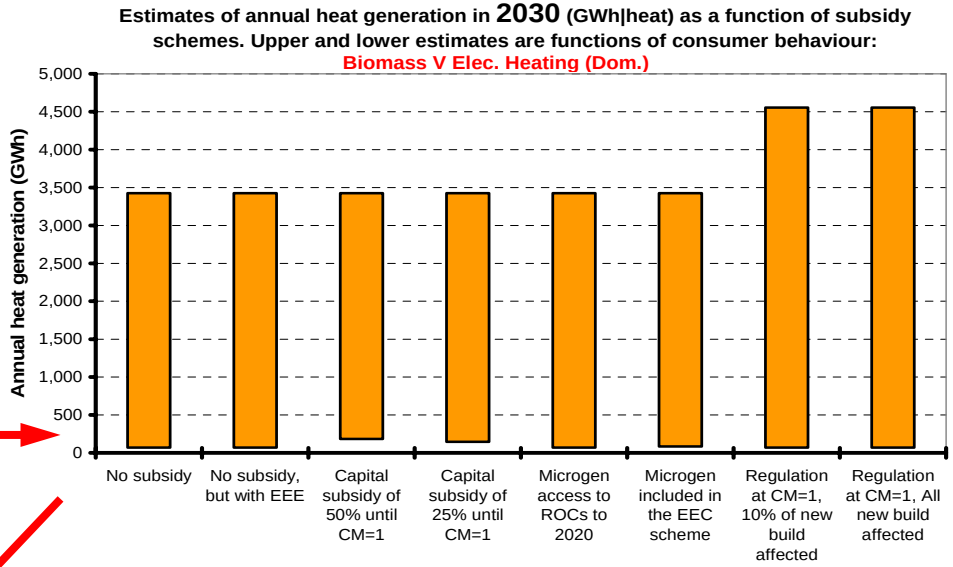
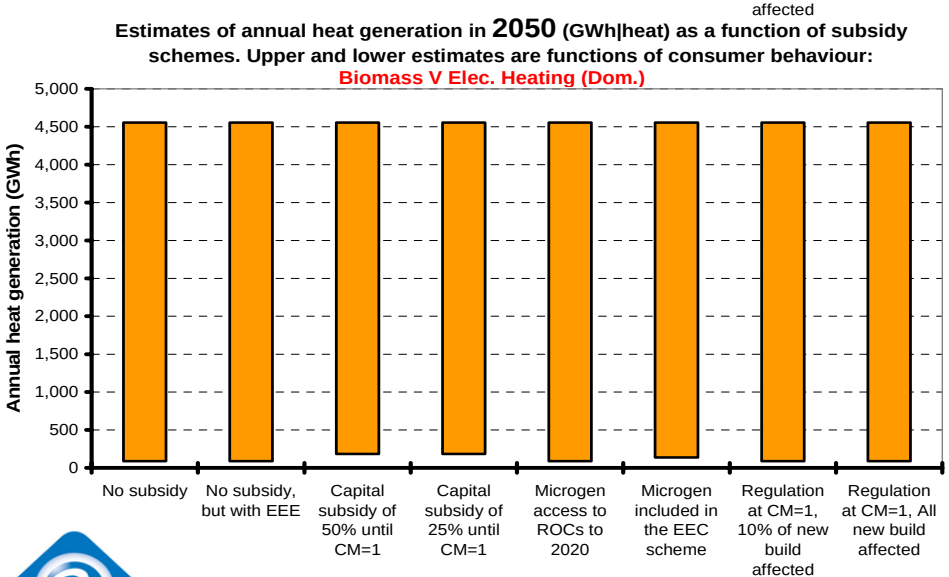
Biomass heating: as with GSHP, regulation helps near term, but long term it saturates its target market without support.







Note that only biomass replacing electric heating is referred to here; the technology is less suited to replacing other heating types.

To achieve market share in these other markets, substantial grants would be required.

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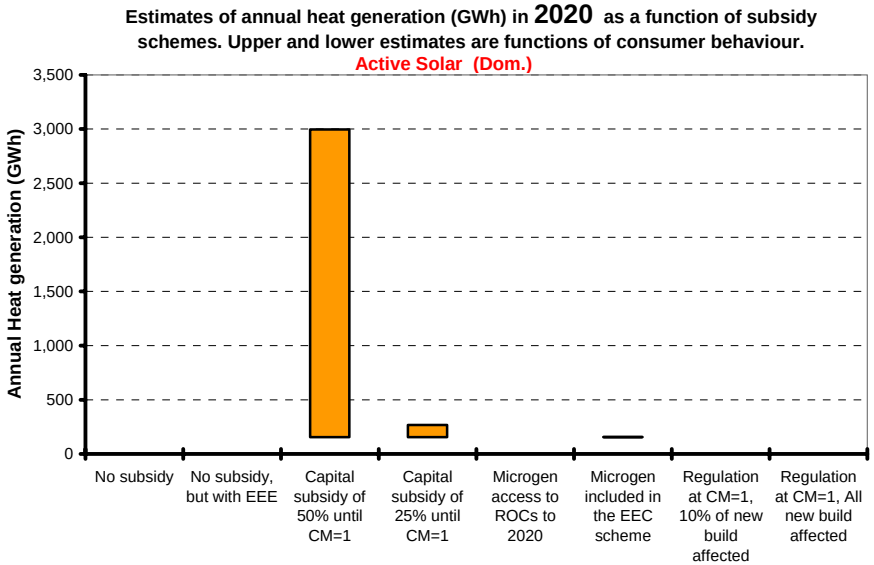
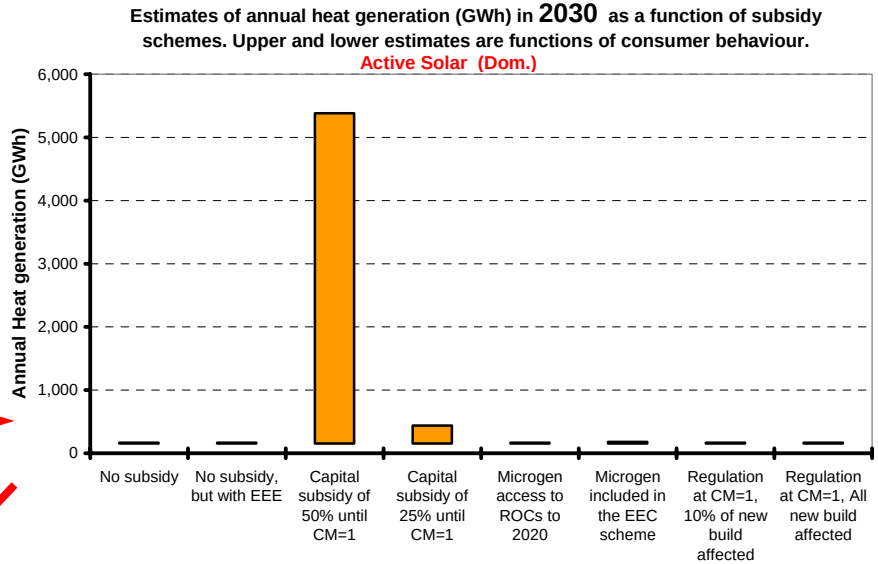
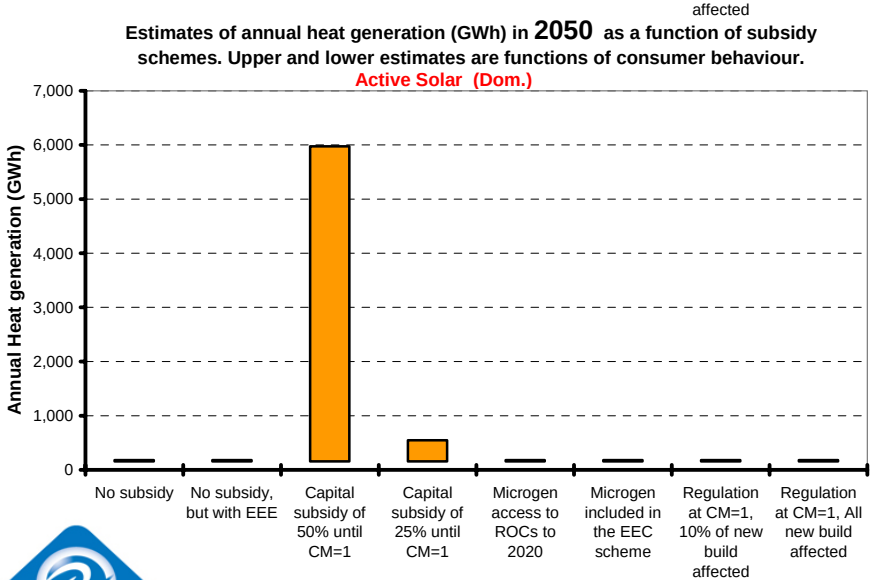
Solar water heating: significant grant funding would need to be maintained in the long term.







Even when compared against electric heating, solar water heating is not predicted to be competitive (in 2050 ASH still has an on-cost).

Maintaining the current subsidies for the technology is vital to sustaining the market towards achieving its potential in 2050.

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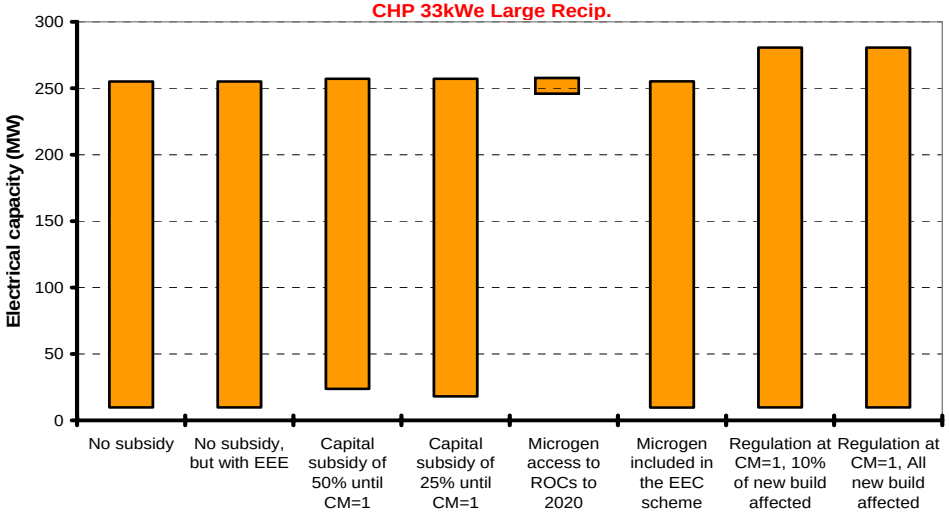
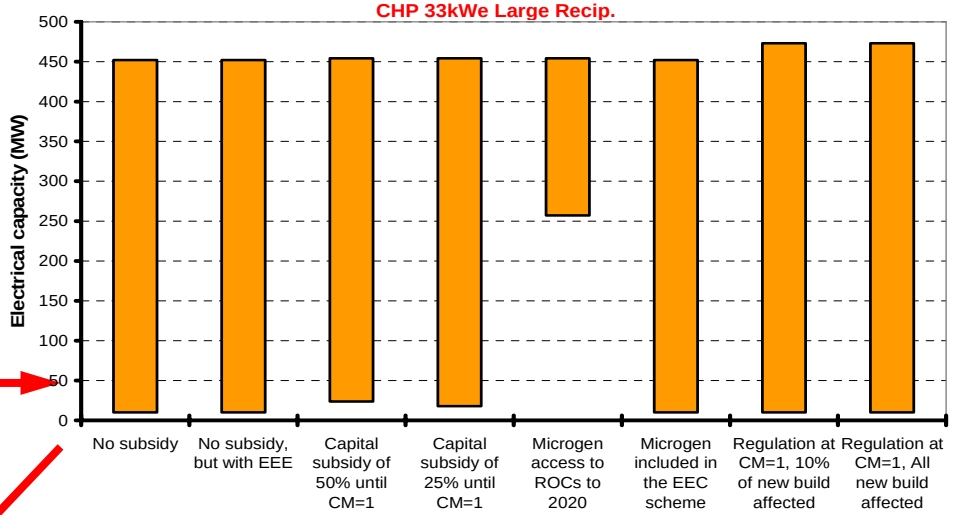
Large CHP: ROC's could have significant impact in the near-term. The users approach to risk is more important than support for uptake.

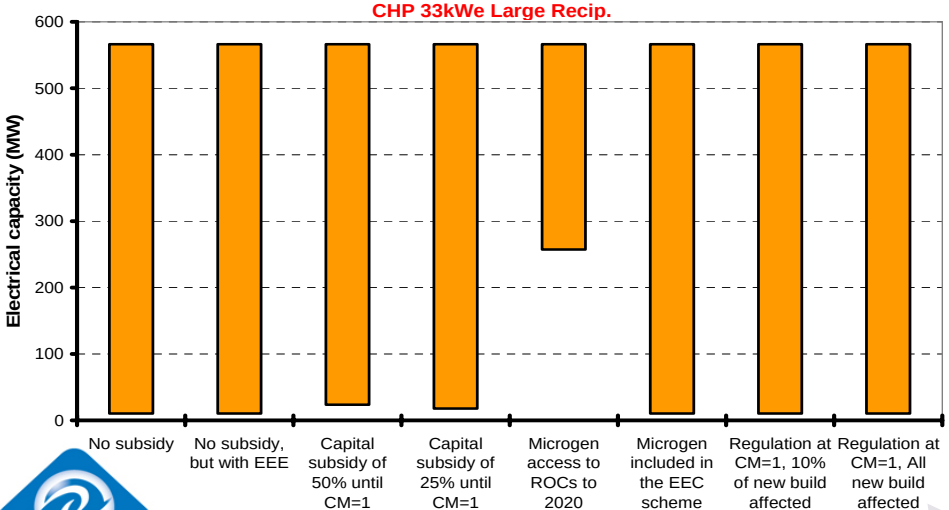
Estimates of cumulative capacity in 2020 (MW) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
CHP 33kWe Large Recip.



Estimates of cumulative capacity in 2030 (MW) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
CHP 33kWe Large Recip.



Estimates of cumulative capacity in 2050 (MW) as a function of subsidy schemes. Upper and lower estimates are functions of consumer behaviour:
CHP 33kWe Large Recip.



Marginal cost effectiveness of larger CHP schemes can lead to limited uptake.

The requirement of the "reluctant consumer" for a P0 = 0.8 constraints uptake.

Only access to ROC's in the near term would persuade the "sceptical" consumer to invest.

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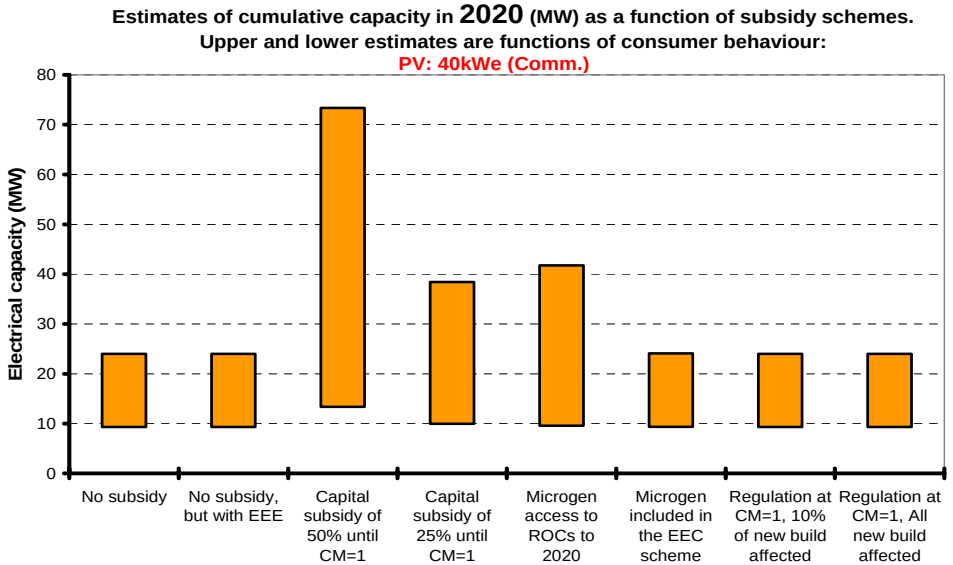
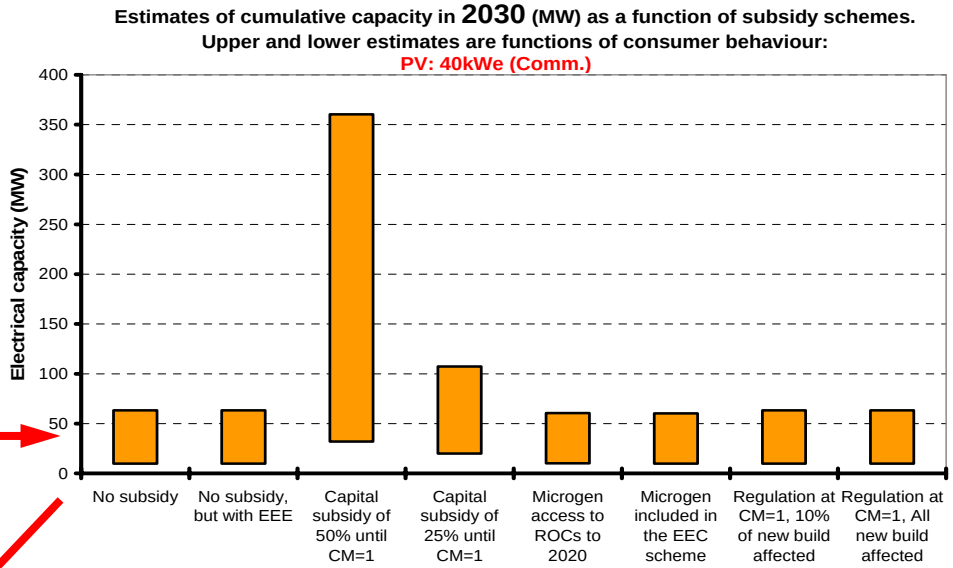
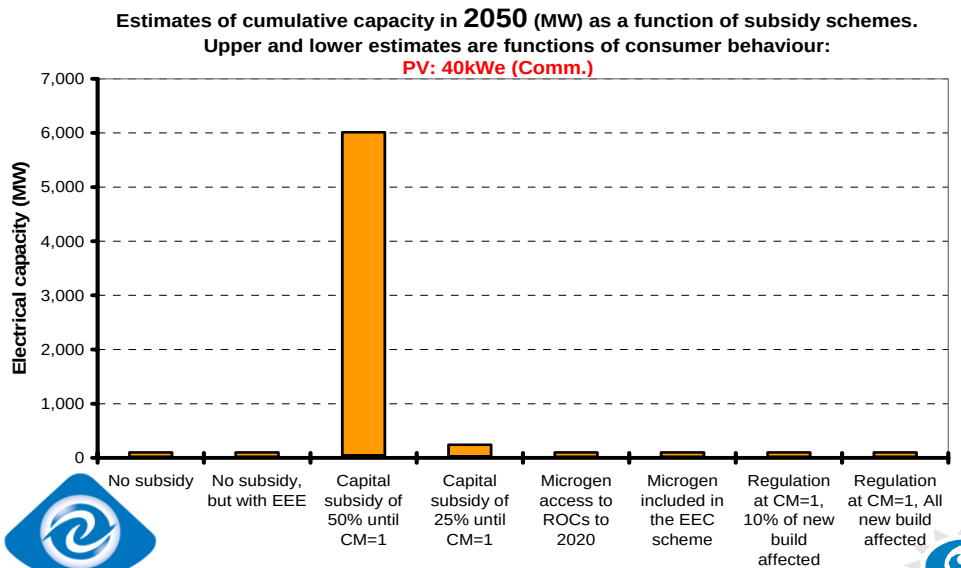
Photovoltaics (40kW): A substantial support scheme is vital to larger (commercial) scale PV.







Except in niche markets such as off grid power and premium facades, larger PV systems will find it difficult to compete with commercial rate electricity.

A continuation of the current capital funding would be required long-term, to ensure the technology approached its saturation capacity in the UK.

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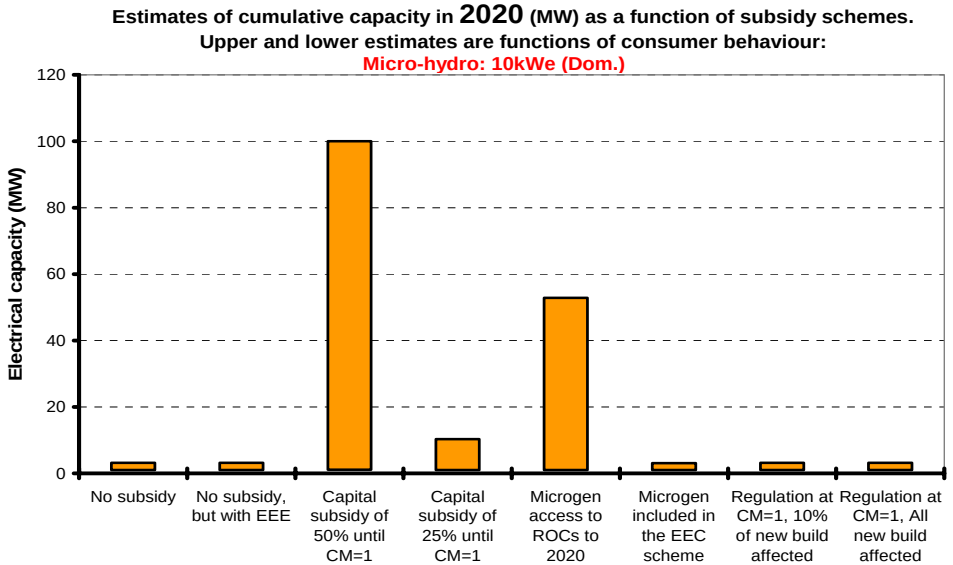
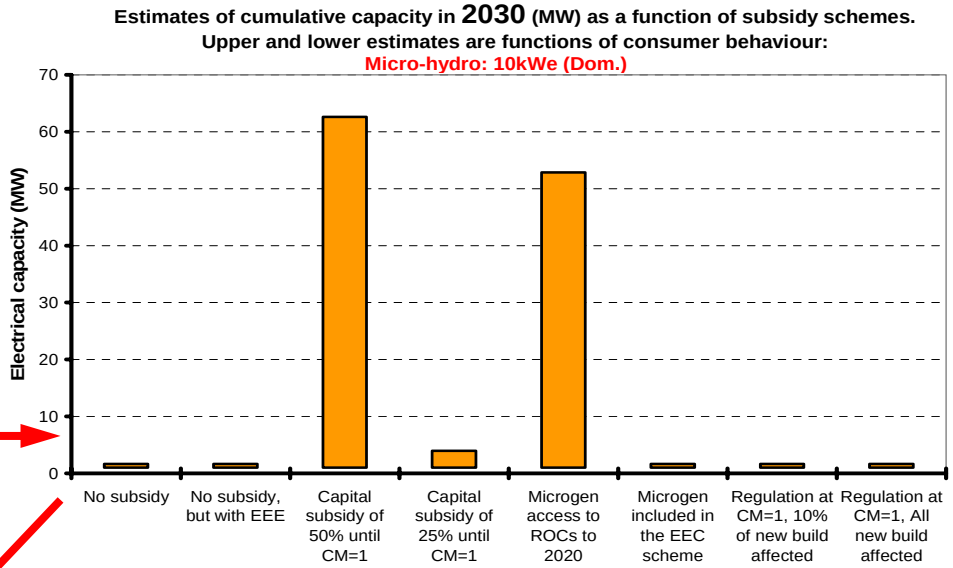
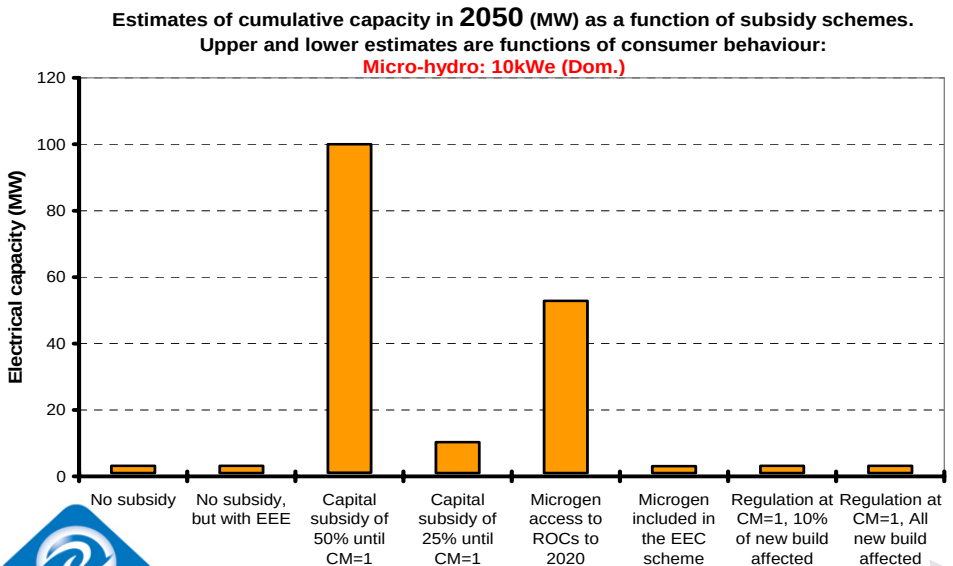
Large Micro Hydro: access to ROC's is as effective as substantial capital funding.







The potential for micro-hydro is limited by suitable sites in the UK.

The potential of these sites will best be accessed by simplified access to ROCs and/or a capital subsidy scheme providing 50% of the capital costs of a micro-hydro scheme.

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Contents

The table below summarises the CO_2 emissions assuming a range of different support schemes, highlighting key results.

The table below summarises results for CO_2 emissions avoided (expressed as a percentage of UK domestic CO_2 emissions*) for different microgeneration technologies in the uptake model under different government intervention schemes.

	PV: 2.5kWe (Dom.)	Wind: 1.5kWe (Dom.)	Biomass V Elec. Heating (Dom.)	GSHP V Elec. Heating (Dom.)	Active Solar V. Elec Heating (Dom.)	CHP 1.2kWe Stirling - Large House	Fuel Cell - 1kWe (small house)	FC: 3kW (large house)
2030								
No subsidy	0.0%	0.3%	0.6%	0.9%	0.0%	0.3%	0.2%	0.1%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	0.2%	0.9%	0.6%	0.9%	0.0%	0.3%	0.2%	0.2%
Capital subsidy of 25%, whilst costs reduce	0.1%	0.9%	0.6%	0.9%	0.1%	0.3%	0.2%	0.1%
Regulation to introduce tech. in all new build once cost effective	0.0%	0.3%	0.8%	1.6%	0.0%	1.7%	1.3%	0.1%
2050								
No subsidy	0.1%	0.4%	0.8%	1.7%	0.0%	1.9%	2.8%	0.4%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	2.7%	4.2%	0.8%	1.7%	0.0%	1.9%	2.8%	5.5%
Capital subsidy of 25%, whilst costs reduce	0.2%	4.2%	0.8%	1.7%	0.1%	1.9%	2.8%	1.3%
Regulation to introduce tech. in all new build once cost effective	0.1%	0.4%	0.8%	1.7%	0.0%	1.9%	3.0%	0.4%

(*) Based on 198 MT CO_2 p.a. arising from the domestic sector (UK Energy Sector indicators 2005, DTI).

A substantial percentage of UK electricity demands could be supplied by microgenerators.

The table below summarises results for microgeneration electricity production (expressed as a percentage of UK electricity demands*) for different microgeneration technologies in the uptake model under different government intervention schemes (these results are not necessarily additive).

Percentage of total UK electrical energy demand.	PV: 2.5kWe (Dom.)	Wind: 1.5kWe (Dom.)	CHP 1.2kWe Stirling - Large House	Fuel Cell - 1kWe (small house)	FC: 3kW (large house)
2030					
No subsidy	0.1%	0.4%	1.0%	0.7%	0.3%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	0.2%	1.3%	1.0%	0.7%	0.6%
Capital subsidy of 25%, whilst costs reduce	0.1%	1.2%	1.0%	0.7%	0.5%
Regulation to introduce tech. in all new build once cost effective	0.1%	0.4%	5.5%	4.5%	0.3%
2050					
No subsidy	0.1%	0.6%	6.3%	9.3%	1.3%
Energy Export Equivalence (i.e. exported electricity sold for the same value as imported)	3.8%	6.0%	6.3%	9.4%	18.4%
Capital subsidy of 25%, whilst costs reduce	0.3%	5.9%	6.3%	9.3%	4.4%
Regulation to introduce tech. in all new build once cost effective	0.1%	0.6%	6.4%	10.0%	1.3%

(*) Based on 380 TWh of electricity p.a. required in the UK (2005).

Contents

An assessment has been made of the implications of substantial microgeneration on the UK electricity system.

Objectives

- Identify the mechanisms by which microgeneration technologies might affect orthodox electricity distribution networks.
- Identify which of these are likely to become important as the capacity of microgeneration increases.
- Calculate the costs required to mitigate these effects.
- Add these costs to the model, if they are substantial.

Approach

- A section of the distribution network is modelled.
- Scenarios are run in a model of different penetration scenarios.
- Issues are identified, and the costs to mitigate these effects are identified, for the modelled network.
- Costs are extrapolated to give an order of magnitude estimate of cost to mitigate system effects.

Voltage rise begins to cause problems with a 50% penetration of 1.1 kWe generators.

Voltage rise is the first network issue encountered as micro-generation penetration levels increase

- Voltage levels have to be kept within statutory limits.
- Without microgenerators, voltage levels tend to drop along distribution feeders, moving further away from the 11kV transformer.
- The transformer is set to avoid unacceptably low voltage at the end of the line
- With microgeneration, voltage may rise beyond unacceptable levels.
- Results indicate that unacceptable voltage variation begins to occur at 50% penetration levels (i.e. 50% of houses with 1.1kW generator – 550W per house).
- Mitigation involves either changing the tap settings on the transformers or replacing the transformers.

Reverse power flow occurs when microgenerators generate more electricity than demand when penetration is ~ 1.4 kWe per house.

Reverse power flow is the second network issue encountered as micro-generation penetration levels increase

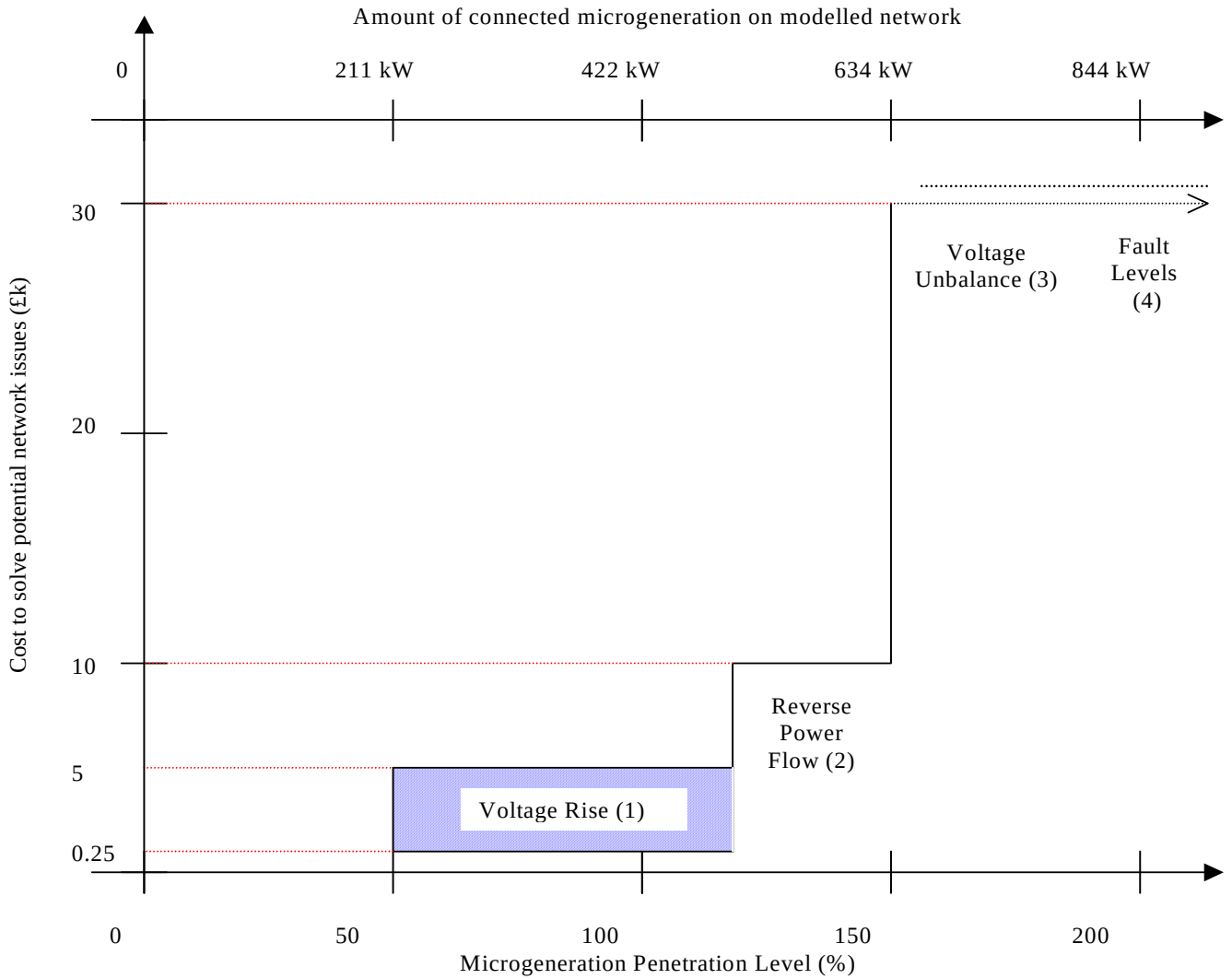
- Most distribution system transformers are designed to take power going in one direction only.
- As microgeneration capacity increases beyond the load on the distribution network, power can begin to flow in the reverse direction.
- Problem only occurs after circa. 130% penetration (1.4 kWe per house).
- Mitigation can be achieved by changing the transformers that cannot accept reverse power flows.

Key findings from the network model – voltage unbalance, fault level and thermal ratings.

Voltage unbalance, fault level and thermal ratings are further network issues encountered as micro-generation penetration levels increase

- Voltage unbalance - An extremely unlikely situation where all the microgeneration is connected to a single phase, and none to any other phase, such that voltage unbalance limits are exceeded. Modelling showed problem occurring at 150% penetration levels. Mitigation involves connecting generation, or the household with the installed generation, to an alternative phase.
- Fault levels – the fault contribution of the generation can cause the overall fault level to exceed limitations. Limitations relate to the design fault level of network equipment. Modelling showed problem occurring at penetration levels in excess of 300%. Mitigation involves replacement of switchgear equipment.
- Thermal limits – where the the capacity of a distribution network feeder exceeds its rated (thermal) limits. This may occur when there is significant reverse power flow. Thermal ratings of feeders are likely to be exceeded after penetration levels have already resulted in the upgrade of the distribution transformer (i.e. penetration greater than 130%). Replacement of the feeder would be required.

It is possible to estimate the cost of mitigation methods for a 400V feeder as the penetration of microgeneration increases.



Results from LV network model, displaying estimated cost of solving potential issues for a single section of distribution network (single 11kV/400V distribution transformer and below), consisting of 384 houses.

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Estimation of cost of mitigation methods for 33kV/11kV substation and 11 kV/400V network.

Issue	Lowest cost estimate	Highest cost estimate
Voltage rise problems at approximately 50% penetration levels (10MW)	Mainly tap adjustment, minimal transformer replacement £30,500	All transformers require replacement £176,000
Reverse power flow at approximately 130% penetration levels (28MW)	Generators already fitted with power factor control to reduce reverse power flow	All transformers require upgrading and primary substation also requires modification of tap changers £500,000

These results can be extrapolated to the entire GB electricity network, though results should be treated with caution.

The extrapolated results should be used with extreme caution. Distribution networks around Britain vary very widely, and the micro-generation penetration levels at which network problems may occur, and the costs of mitigation measures, will not apply uniformly. Results shown below are extrapolations of the SIAM report figures *. Extrapolation assumes that penetration levels on the GB network which result in the need for mitigation are similar to the penetration levels requiring mitigation on the modelled network.

Voltage rise

Micro-generation average penetration level	Estimated cost of changing taps in rural areas	Estimated cost of changing taps in urban areas	Total costs of changing taps
20%	£9-12m	0	£9-12m
50% (13.75 GWe)	£23-31m	£99-104m	£122-135m
70%	£32-43m	£139-146m	£171-189m

Reverse power flow

Micro-generation average penetration level	Cost of upgrade of 11kV/400V transformers	Estimated cost of upgrade of 33kV/11kV transformers
100%		£27-30m
133%	£28-31m	

(*) System Integration of Additional Microgeneration. Mott McDonald. DTI. 2004.

Extrapolation from the modelled network suggest similar costs to SIAM, though DNO estimates are higher.

Two alternative extrapolations, avoiding SIAM figures, are shown below.

1. Extrapolation from cost estimates for the modelled network

Network issue	Lowest cost estimate	Highest cost estimate
Voltage rise at approximately 50% penetration (13.75 GW)	£150m (mainly tap adjustment)	£240m (transformer replacement)
Reverse power flow at approximately 130% penetration	Unknown (mainly generator power factor control)	£650m (transformer upgrade)

2. A DNO estimate of costs to mitigate network impacts

- £100 per household to mitigate micro-generation impacts, total investment £2.5b
- Investment may be triggered at 50% penetration (13.75GW)
- In some circumstances, on a worst case scenario, investment may be triggered at 20% penetration (5.5GW)

There are substantial benefits to the network through installation of micro-generation.

- Potential reduction in peak demand on the distribution network
- Potential reduction in annual demand on the distribution network
- Potential reduction in losses

Summary of network issues.

Network issues

- Voltage rise is the first network issue encountered in the model as micro-generation penetration levels increase.
- Followed by reverse power flow.
- Voltage unbalance unlikely to cause a problem.
- Fault level constraints were not encountered in the model.
- Following reverse power flow, thermal constraints may be encountered.
- All network issues are location specific i.e. the micro-generation level which triggers the need for mitigation measures will be location specific, as will the cost and nature of the mitigation method.

Mitigation

- Any network issue can be resolved.
- This is a matter of economic rather than technical limitations
- Extrapolation to the GB system is very difficult, ranging from £150m-£240m to mitigate voltage rise, £60m-£650m to mitigate reverse power flow, and £2.5b (DNO estimate) to mitigate all network issues.
- Alternative mitigation methods, other than the traditional reinforcement, are possible.

Potential For Microgeneration

Appendices

A1 – Detailed description of technology modelling

A2 – Uptake modelling assumptions

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Contents

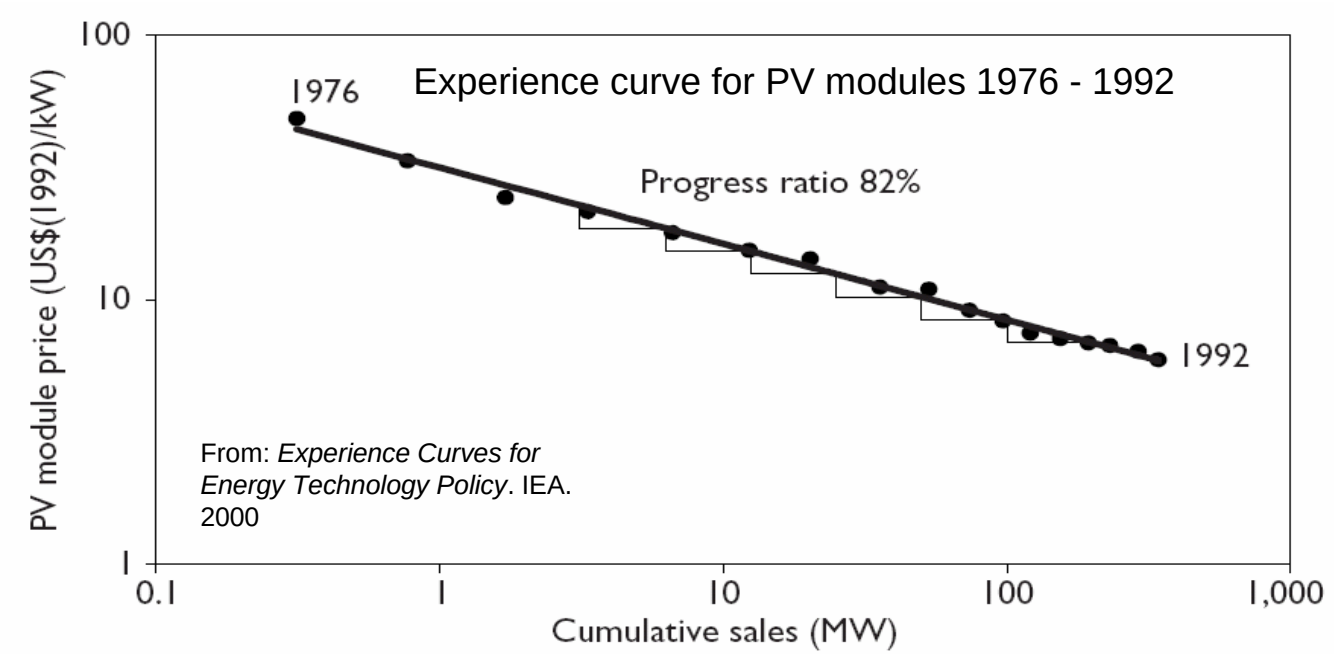
A global technology cost model allows projection of the costs of microgeneration technologies to 2050.

Global costs to 2050 are modelled using learning curve analysis:

- Historically, equipment capital (installed) costs have been observed to decrease over time as a function of cumulative production levels, giving a learning rate.
- These learning rates are used to predict future costs over the period to 2050.
- These are predictions of “global” costs. For most technologies (e.g. photovoltaics), variation in uptake levels in the UK will not affect global technology price.
- Cost predictions are dependent on worldwide production meeting predicted levels.
- The result of this is that technology cost is exogenous to the UK uptake model which is presented later.
- Use of median, high and low predictions for technology cost allows representation of endogenous effects where these could be relevant e.g. for small wind or micro-CHP, where the UK could lead worldwide introduction of the technology.

Learning curves relate cost reduction to installed capacity.

- Learning curves demonstrate a linear proportionality between *log(cost)* and *log(cumulative capacity)*.
- This indirect relation can include the effects of economies of scale, technological improvements, and other cost cutting measures.
- A doubling of cumulative volume (units, systems or installed capacity etc) provides a cost reduction expressed as a percentage – the learning rate *.
- For example, the PV learning rate was historically 18 %. Current estimates range between 18 % and 20 %:



(*) The learning rate can also be expressed as a progress rate. This is 1 minus the learning rate.

Key stages for modelling global cost projections:

1. Acquire absolute data on installed capacities and annual installations for each technology type. Analyse current growth patterns on a global scale.
   - Use published data where available.
   - Where little or no data is available (e.g for new technologies), approximate growth based on similar technologies, or through using projections.
2. Model future growth to 2050 – sense check values with global capacity and other projections.
3. Input current capital cost data (£/kW) and technology learning rate.
   - Learning rate can change with time as technology matures.
4. Calculate future capital costs based on cumulative installed capacity and learning rate – sense check projected costs with industry projections.

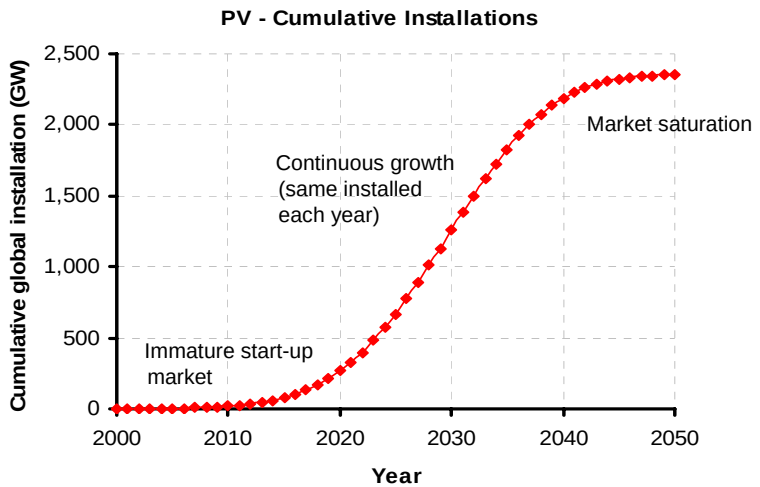
PV example: global market growth.

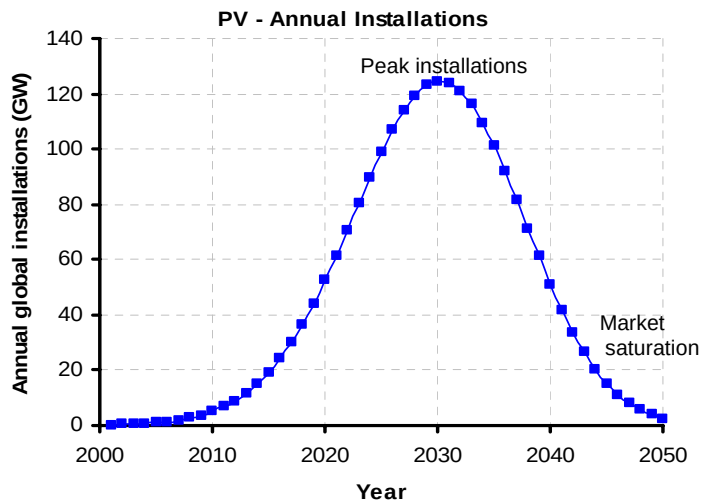
Initial growth conditions:

- 2064 MW cumulative capacity.
- 45 % annual growth (increase on previous years installations).

Growth progression:

- -2 % change in annual growth per year (this value is used to reduce growth with market maturity).





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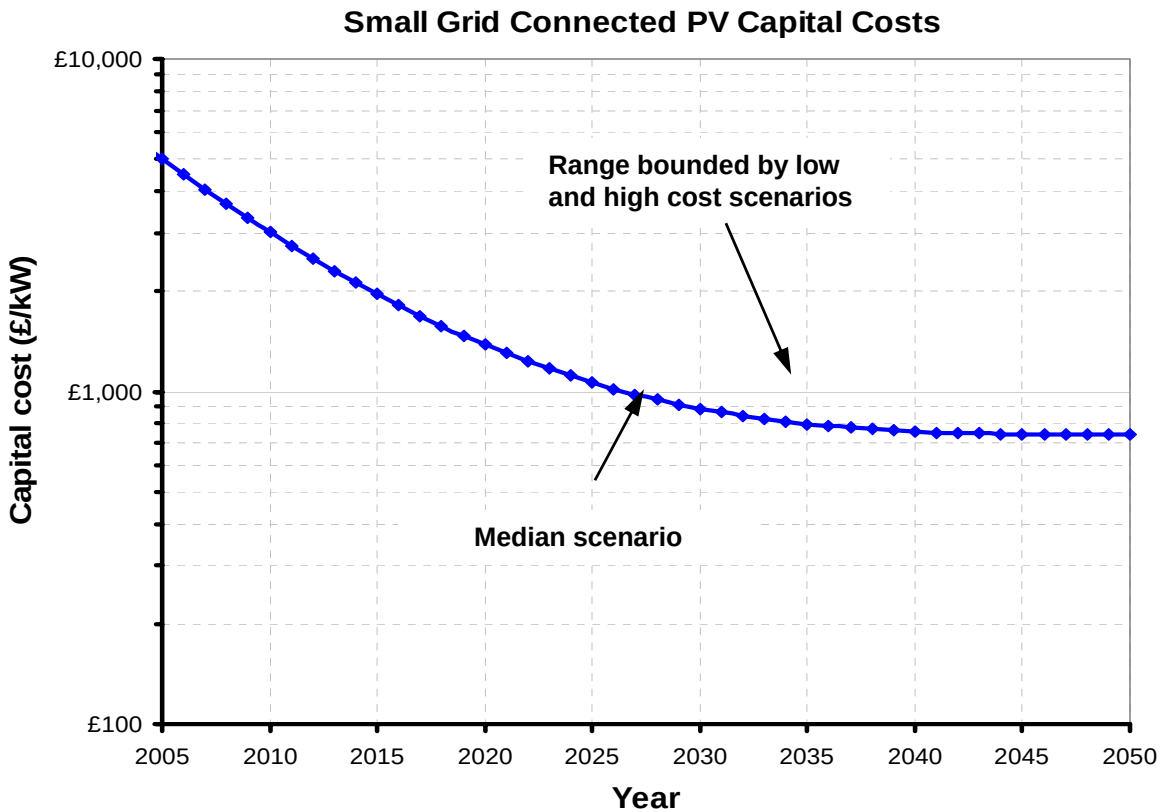
PV example: capital cost projections.

- Learning rate used to calculate median unit cost from cumulative installed capacity.
- Higher growth earlier in the timescale causes large cost reductions.
- Lower growth as market saturation is reached prevents further cost reductions.
- Low and high cost scenarios are created by varying growth change and learning rate conditions.



Notes on global market model.

1. The model gives the universal technology deployment *S*-curve characterised by steepness (which determines the deployment timescale).
2. The shape of the model is heavily based on the initial parameters, in particular the annual growth and annual change in growth – values need to be taken from reputable data where possible.
3. Input values can be 'sense checked' to ensure output is credible (i.e. not a higher capacity than current global capacity!).
4. The model does not account for an expanding market (population growth).
5. The model does not account for replacement sales and upgrades. These values would be low compared with peak sales and so have little effect on cost reduction via learning.
6. Where data on growth and learning rates not available, estimates are based on similar technologies or industry projections. These values for growth and learning should not be treated as absolute, but as a tool for projecting realistic costs.

Contents

Cost of energy from microgeneration.

The cost of energy (£/kWh) from each microgeneration technology is calculated accounting for:

- Annualised capital cost.
- Maintenance cost (as a percentage of capital cost).
- Annual fuel cost (where relevant).
- Annual energy output (with UK specific performance characteristics where relevant).
- Interest rate of 8 %.
- Loan length made equal to lifetime (based on manufacturers warranty where available).

These values are then compared with baseline energy costs:

- Baseline costs are the offset energy cost, i.e. the value of replaced energy.
- The baseline cost for PV and wind for example is the grid electricity cost.
- Baseline for heating technologies is either natural gas and boiler installation, or electrical heating.
- For CHP technologies, a “hybrid” baseline energy cost is used. This is a weighted average of heat and electricity replaced.

Excess electricity exported to the grid is currently sold at a reduced export sale price.

- The **Export sale price** is currently £0.0256 / kWh *. Industrial electricity trends are used to project the export sale price to 2050.
- The **Export percentage** is the proportion of electricity exported to grid. This is set at a fixed percentage for each technology #:

Microgeneration technology	Percentage of electricity exported to grid #
PV	50 %
Wind	60 %
Hydro	50 %
CHP	33 % (72 %) **

- The **Effective base cost** is a ratio of the value of electricity used and the total export sale revenue for the electricity exported to the grid. For example, with 33 % export:

Effective base cost / kWh = 0.67 × (grid electricity price / kWh) + 0.33 × (export sale price / kWh)

(*) This is a weighted average of the Relevant Metered Output Price (RMOP) over each settlement period.
(#) Data taken from Metering, Settlement, and Export Reward – Options for Micro-generation. Ilex Energy Consulting. DTI. 2005.
(**) A 72 % export value is modelled for the generic 3 kWe/3 kWth fuel cell CHP system designed to operate as a de-centralised grid generator.

Metering options: the role of Energy Export Equivalence (EEE).

Two metering options are discussed for the sale of electricity to the grid:

Energy Export Equivalence (EEE)

- In our model, the export sale price is set equal to the purchase price of grid electricity *.
- The base energy price is therefore the grid electricity price appropriate to the operator.
- The effect of this is identical to 0 % export.

Non EEE

- Excess electricity is exported to the grid and sold at a reduced price *.
- The base cost is lowered to the effective base cost level.
- Non EEE reward increases the cost per kWh of electricity consumed by the operator due to the exporting of electricity at a loss.

(*) In both cases the price reflects a market distortion. Without EEE, the microgenerator is not paid a reasonable price for the distributed generation services it provides. With EEE, the network operator is not paid a fair price for the services it offers. A 'fair rate' will lie somewhere between the two extremes.

Contents

Projections for the baseline gas and electricity costs until 2050 are based on three scenarios provided by DTI.

Three scenario projections for the baseline fuel cost are based on fossil fuel cost predictions until 2020 and with simple extrapolations from 2020 – 2050:

2005

- Prices taken from published data (DTI Quarterly Energy Prices, June 2005).

2005 – 2020

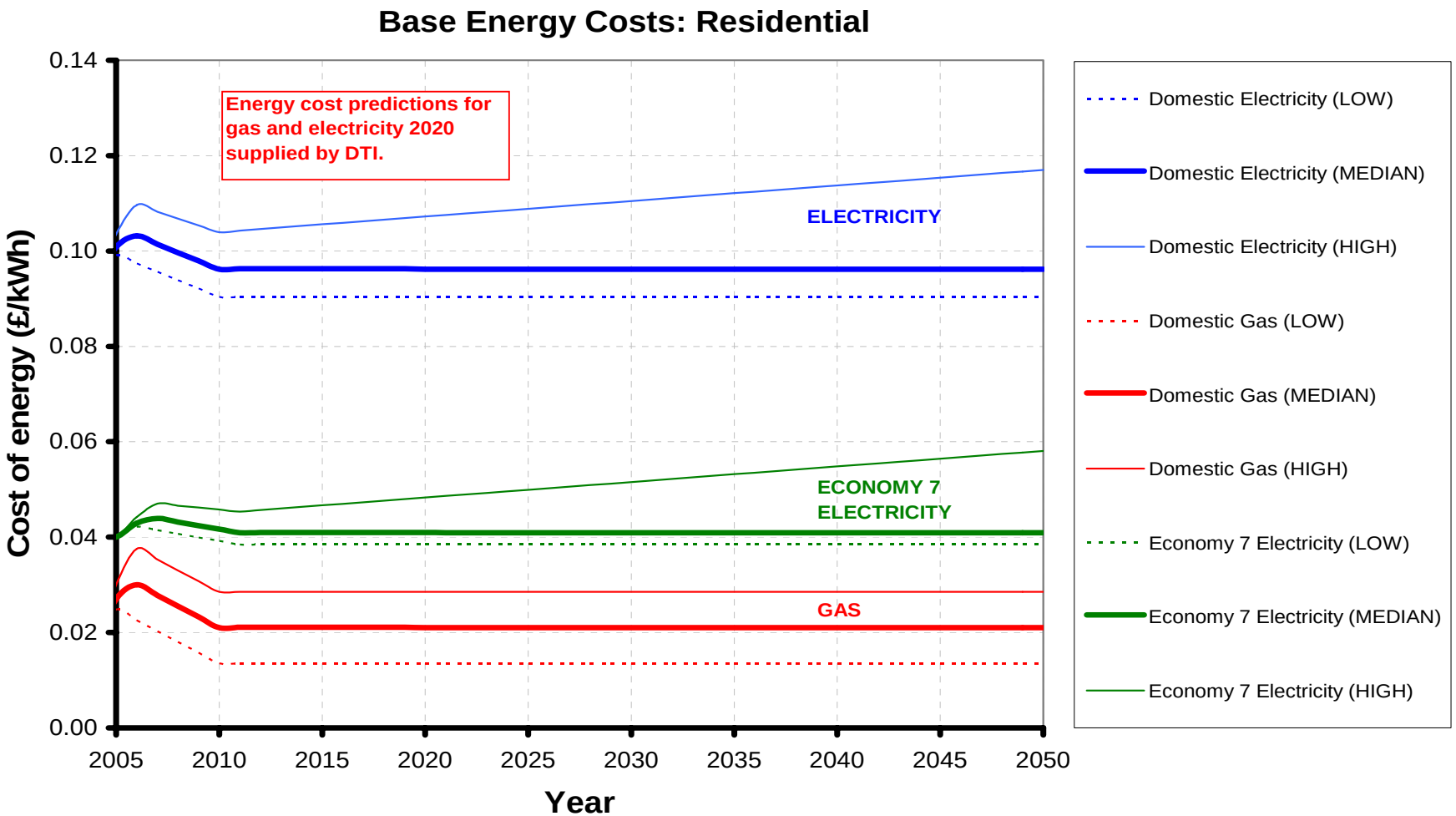
- Predictions based on DTI data giving beached natural gas costs projected until 2020 for low, median and high scenarios*.

2020 – 2050

- Gas: prices are constant from 2020 levels for all three scenarios.
- Domestic electricity: low and median scenarios are constant from 2020 levels. High scenario price rises are due to increased generation costs.
- Economy 7 electricity: follows the standard domestic electricity trends #.
- Commercial electricity: all scenarios are constant from 2020 levels.

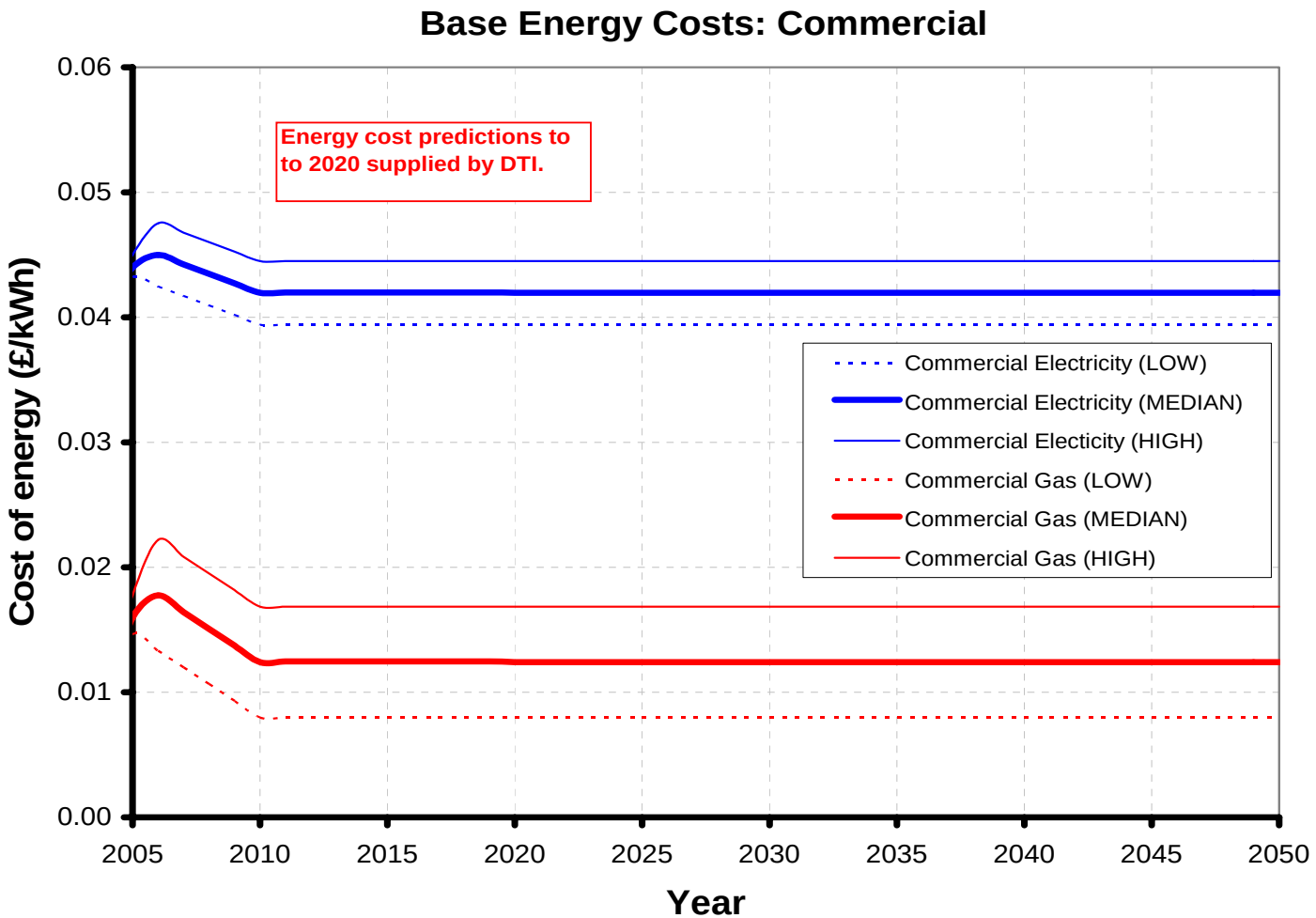
(*) This data was provided by the DTI and is also being used in the Climate Change Programme Review.
(#) The Economy 7 cost varies with supplier. £0.04 / kWh is used for 2005 representing the upper price range for night time electricity. Daytime electricity for Economy 7 users is assumed to follow standard tariffs, although the cost is often higher depending on electricity provider.

Gas and electricity baseline fuel costs for residential consumers are projected to 2050 (based on DTI figures for the near-term).



Note: The Economy 7 cost varies with supplier. The 2005 value of £0.04 / kWh represents the upper price range for night time electricity.

Gas and electricity baseline fuel costs for commercial consumers are projected to 2050 (based on DTI figures for the near-term).



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Heating baseline costs.

Condensing gas boiler space and water heating

- The capital cost projections are modelled using a learning rate and growth value*.
- Limited cost reduction predicted: £65 / kW (2005) to £59 / kW (2050)#.
- Cost of thermal energy (£ / kWth) calculated using gas price projections**.
- The gas price is dominant in the cost of energy generated. The gas price trends are thus the major influence on changes in cost over time.
- Oil boiler heating cost is very slightly higher than gas but the difference is negligible when compared with microgeneration energy costs. Oil heating is therefore represented by gas heating.

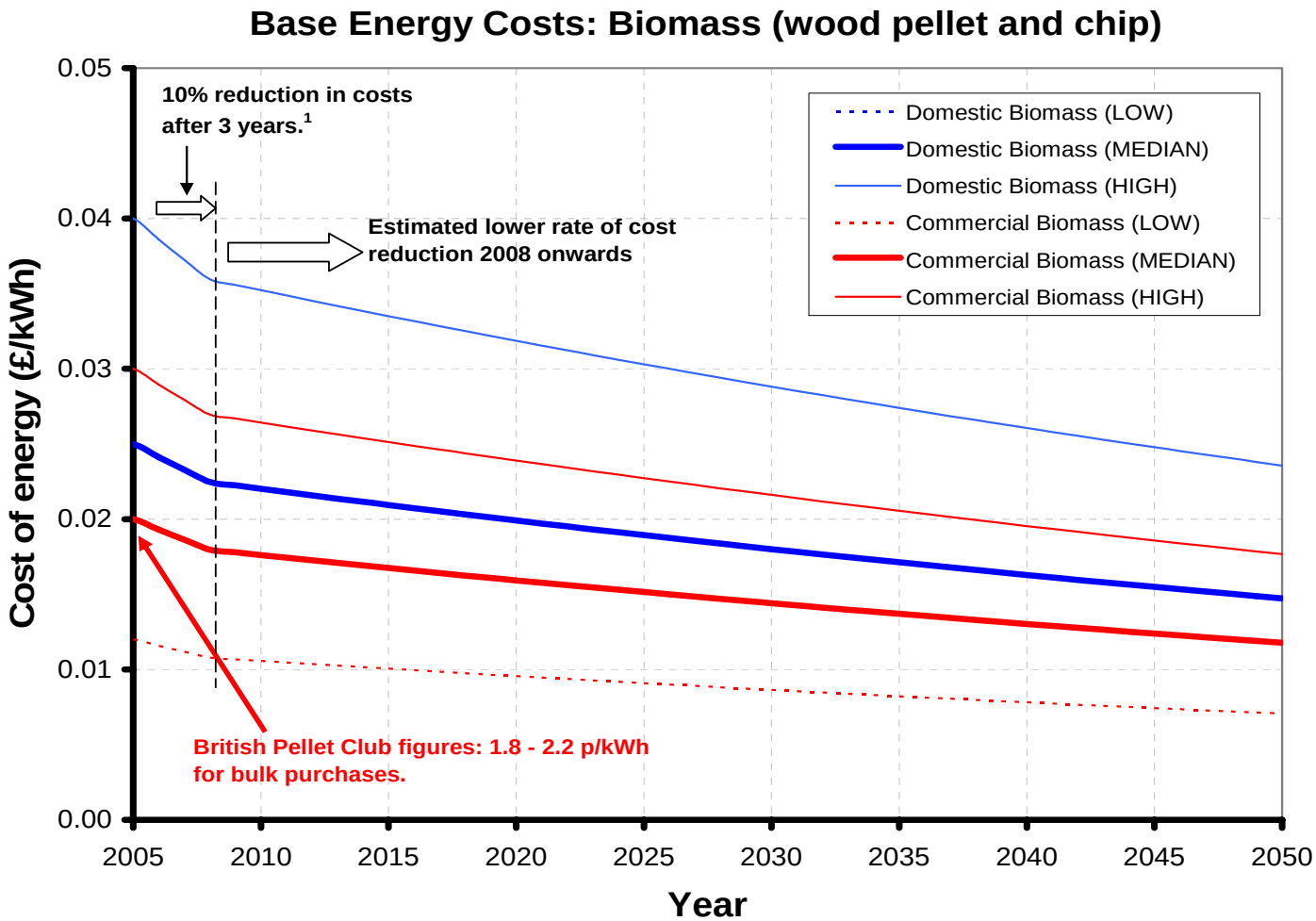
Electrical heating

- Space heating: composed of 50% Economy 7 and 50% standard tariff electricity.
- Water heating: composed of 100% standard tariff electricity.

(*) A low learning rate of 4% and small growth combined with large installed capacity are used to give approximately 10 % cost reduction.
(#) £65 / kW is based on a 20 kW condensing boiler costing £45 / kW (commercial prices) with £ 300 installation costs and £100 in parts.
(**) The cost of energy is calculated for a 90 % efficient 20 kW boiler over a 15 year lifetime operating with 10 % load factor producing 17.5 MWth) p.a. A 5% maintenance cost is assumed.

Biomass fuel costs (wood pellet and chip) : commercial.

- The biomass wood chip and pellet market is currently relatively immature in the UK.
- The cost of biomass depends on the quality, determined by factors such as moisture content.
- The combination of these leads to a wide range of costs.
- Short term projections are based on technical advances and economies of scale *.
- Longer-term projections are based on a smaller cost reduction rate.



(*) Possible support mechanisms for biomass-generated heat. Ilex Energy Consulting. 2003

Contents

Small grid connected PV: installed capital costs 2005.

2005 Installed Capital Costs

Domestic 2.5 kW: £5000 / kW

- The sizing of this system is typical for the UK domestic market, capable of providing a significant proportion of annual domestic demand*.
- This value is based on PV installation experience across the UK.
- Costs are higher than for commercial installations due to economies of scale in power electronics and grid connection costs.

Commercial 40 kW: £4000 / kW

- 40 kW systems are typical for commercial installations*.
- This cost is currently achievable in the UK for commercial grid connected PV installations#.
- The value can vary depending on the building integration issues and grid connection.

(*) Based on a typical UK domestic installation.
(#) The value of £4000 per kW is from historical Energy Saving Trust data and industry knowledge.

PV: scenarios for projected installed costs to 2050.

- PV is an established technology with an accepted learning rate of 18 %*. The learning could increase with the introduction of new 3rd generation technologies increasing module efficiencies and reducing manufacturing costs.
- The current large growth in the global PV market helps reduce the costs via the learning process. Changes to the growth could thus have significant impacts on the projected costs.

Notation:

- Values in red denote changes from median case

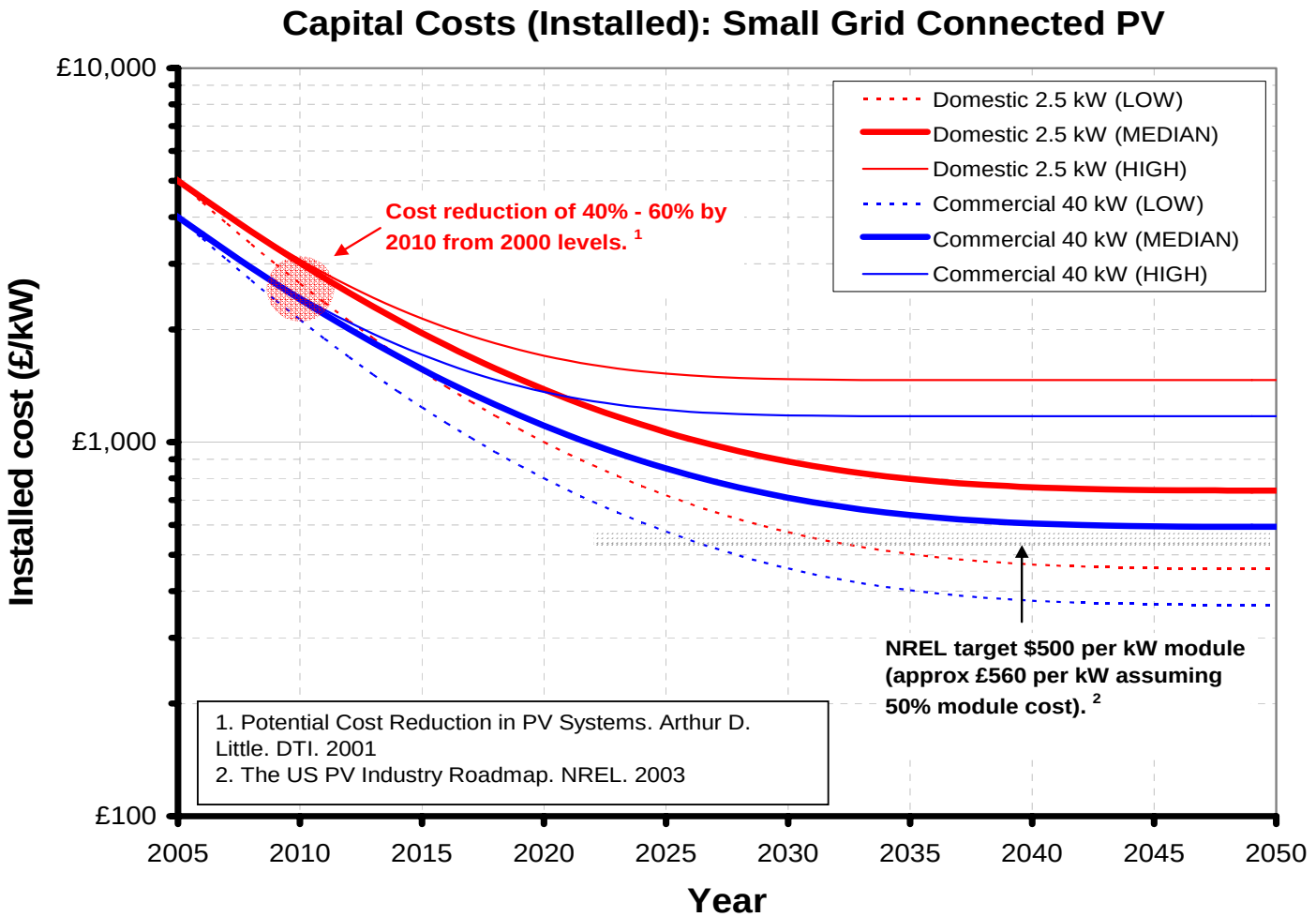
- D – domestic data, C – commercial data

Cost scenario	Rate of change in annual growth per annum (% p.a.)	Learning rate (%)	2050 Cost (£/kW)
Low	-1.75% change per annum *(from initial growth rate of 45% p.a. #)*	*25% (breakthrough in technology – 3rd generation could offer up to 30%)*	£459 / kW D £367 / kW C
Median	-1.75% change per annum *(from initial growth rate of 45% p.a. #)*	18% *(IEA historical value *)*	£742 / kW D £593 / kW C
High	-3% change per annum *(the annual growth reduces more quickly)*	18% *(Unlikely to reduce due to hi-tech nature)*	£1466 / kW D £1173 / kW C

(*) Experience Curves for Energy Technology Policy. IEA. 2000.
(#) IEA International Statistics. IEA Photovoltaic Power Systems Programme. http://www.iea-pvps.org/

PV: projected installed costs for systems to 2050.

- Projected costs in 2020 are in-line with detailed engineering analysis predictions.
- Costs start to stabilise circa 2020 – 2040 due to reduced growth as the market reaches maturity.
- Final costs approach US targets for the median scenario.



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PV: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to model

- These parameters form the basis of the cost-of-energy model to calculate the annual energy generation and total annualised costs.

Parameter	Value	Notes
Rated power	2.5 kW D 40 kW C	Typical of UK installations.
Lifetime	25 yrs	Industry 25 year PV module warranty.
Maintenance cost	1% cap.	Based on a bi-yearly maintenance check. This could increase due to parts required during the system lifetime, e.g. replacement power electronics.
Load factor	9.7%	Based on 846 kWh / kWp p.a. capacity. Average value of UK data from PV-COMPARE project*.

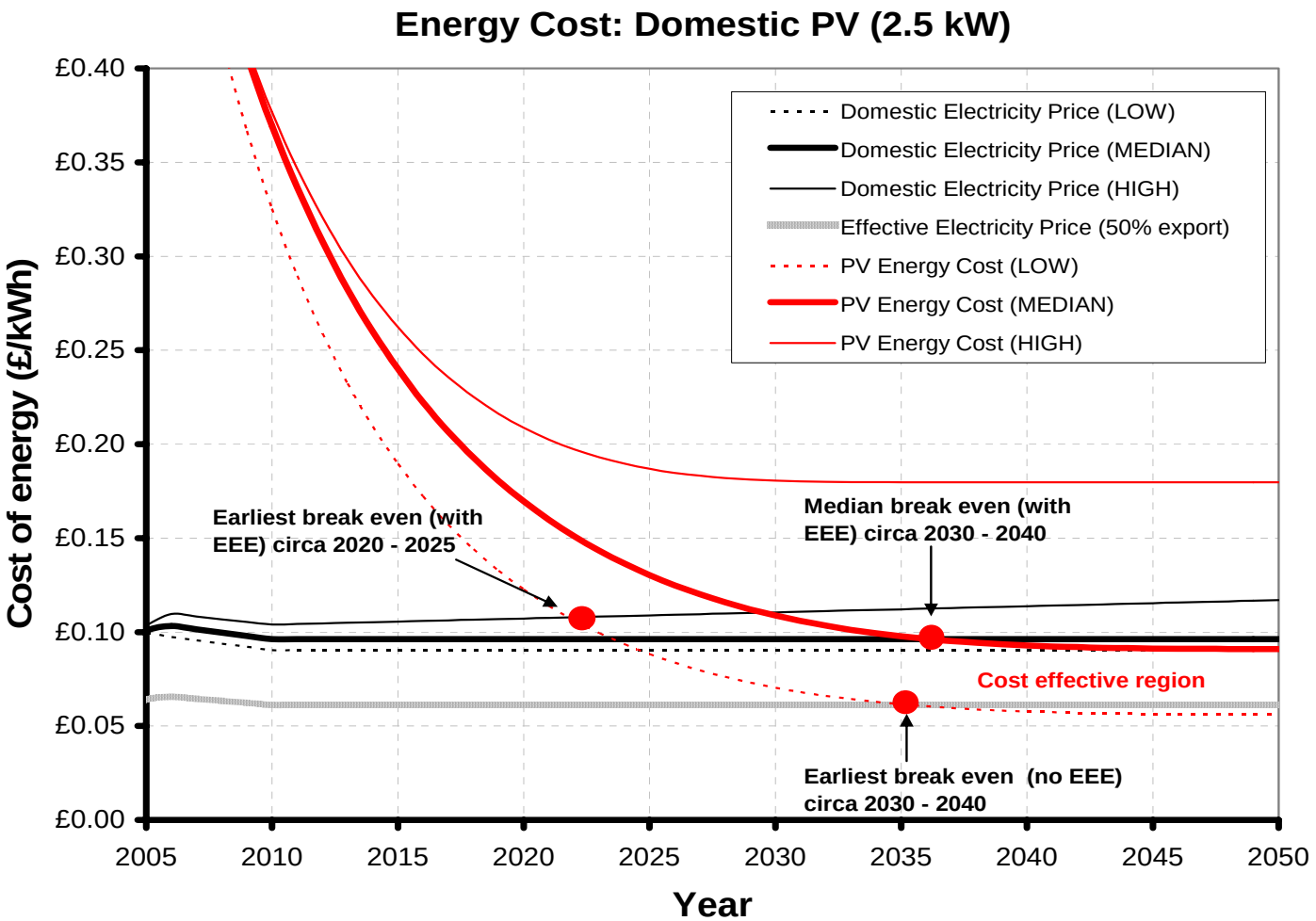
The following base costs are applicable to PV generated electricity:

- Domestic: domestic electricity prices (both with EEE and without EEE).
- Commercial: commercial electricity prices.

(*) PV-COMPARE: Direct Comparison of Eleven PV Technologies at Two Locations in Northern and Southern Europe. Jardine C N, Conibeer G J and Lane K. Environmental Change Institute, University of Oxford. (Review of PV technologies commercially available in 1999)

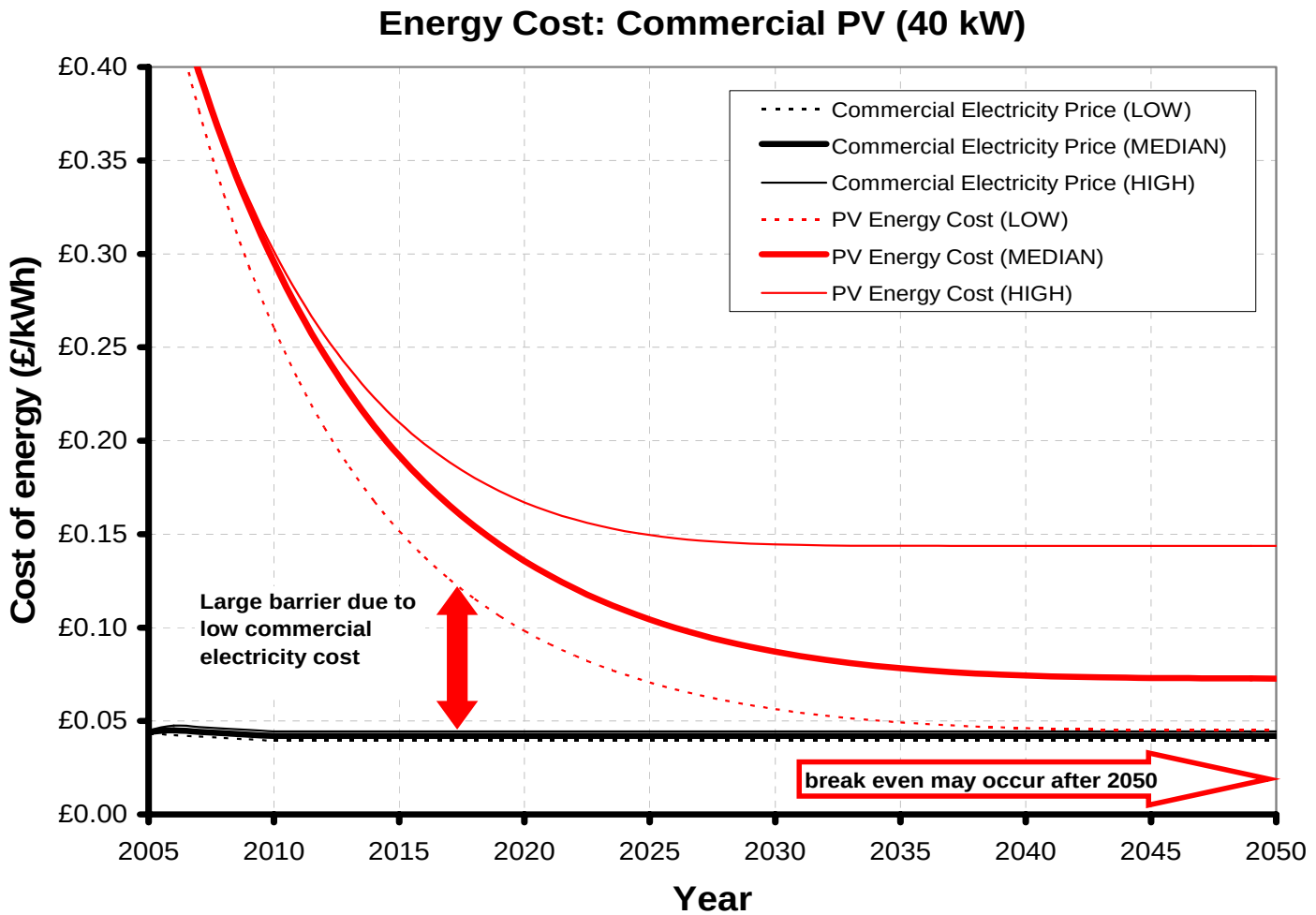
Domestic PV: projected generated energy costs. Break even is not achieved in the short-term.

- Break even is projected for the median scenario circa 2030 – 2040 with EEE.
- Without EEE, break even is not reached for the median scenario due to PV-generated electricity costs stabilising at a higher value than the non-EEE base level.
- A cost/performance breakthrough is necessary for economic operation without EEE.



Commercial PV: projected generated energy costs. Break even is not predicted before 2050.

- Commercial PV is not projected to be cost effective before 2050.
- This barrier is caused by high PV capital costs combined with the low commercial electricity prices (these are amongst the lowest in the EU)*.



(*) DTI Quarterly Energy Prices, June 2005

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Small wind: installed capital costs.

2005 Installed Capital Costs

Domestic 1.5 kW: £3000 / kW

- 1.5 kW is typical of modern small wind turbines designed to help meet modern domestic electricity demand.
- Current costs range £1500 - £5000 / kW for systems circa 1 – 1.5 kW*.
- Historical experience from the Energy Saving Trust suggests £3000 / kW for a 1 kW system. This is also representative of a midrange value from UK manufacturers.
- Present costs could be reduced in the short term to around £1000 / kW for smaller turbines through volume production#. Further reductions with increased sales are also possible following this initial transition.

Commercial 15 kW: £2666 / kW

- Reduction in installed costs with system size due to economies of scale.
- This cost is based on an installed grid-connected cost of £40,000 for a 15 kW turbine*.
- The total installed cost can vary with different requirements for civil works including foundation construction and connection requirements.

(*) UK manufacturers data.
(#) Current installed costs of £5000 - £8000 for a 1.5 kW turbine could be reduced to circa £1500 with a transition to mass production and installation. From discussions with UK manufacturer.

Small wind: scenarios for projected installed costs to 2050.

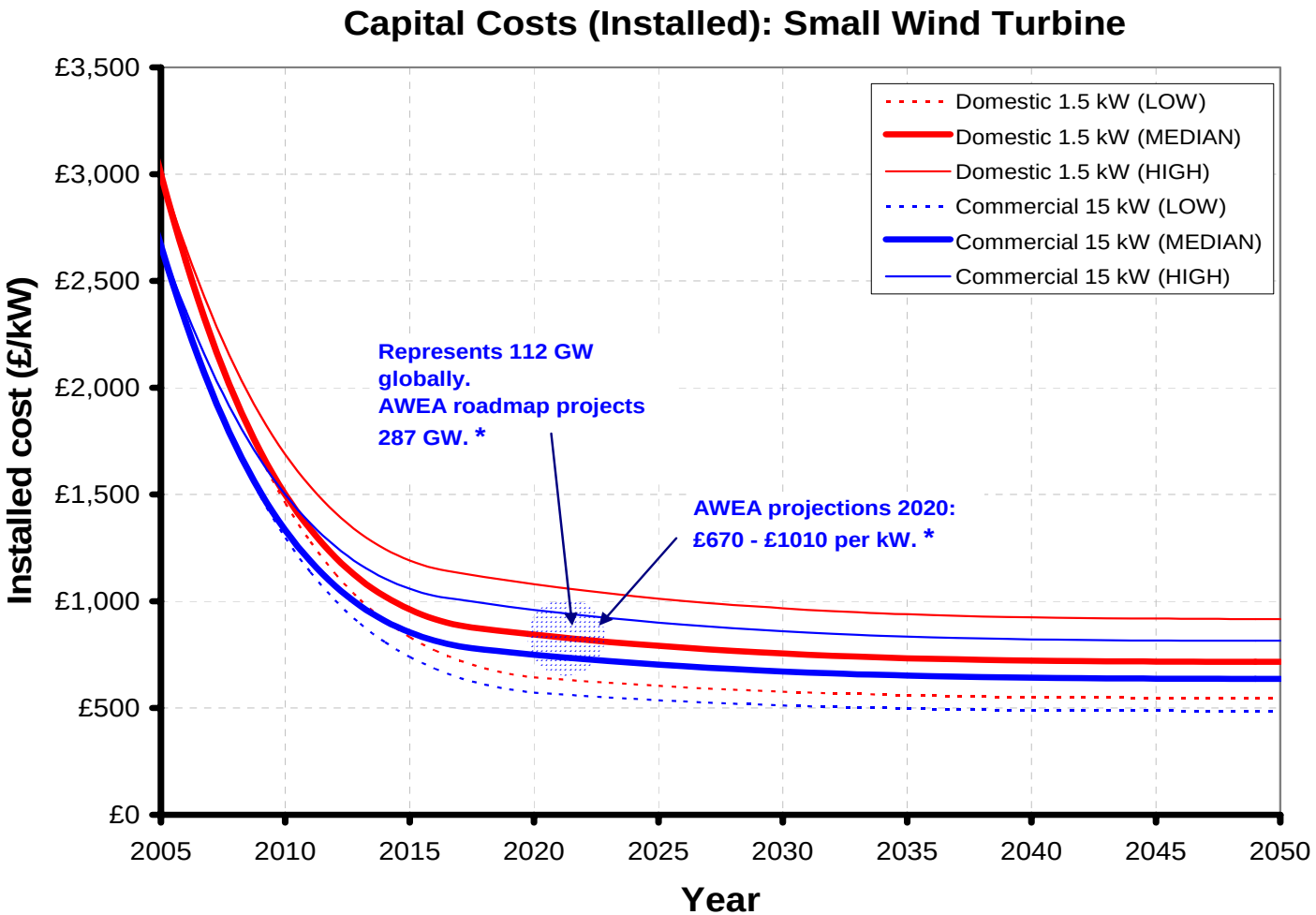
- The volume-manufacture of small wind turbines could provide significant cost reductions in the short term. This gives a strong initial learning rate.
- Learning rates could reduce through the period 2005 - 2050*.
- Three scenarios are created by changing the learning conditions.

Cost Scenario	Initial learning rate (%)	Change in learning rate	2050 Cost (£/kW)
Low	28% *(the learning rate is unlikely to rise above 28%)*	Learning starts to reduce later than the median and high scenarios, giving a more sustained period of strong learning.	£546 / kW D £486 / kW C
Median	28% *(high value due to immaturity of technology. Large scale production could dramatically cut costs)*	Learning rate reduces to a minimum of 5%	£716 / kW D £636 / kW C
High	24% *(represents a reduced potential of lower costs through volume production)*	Learning rate reduces to a minimum of 5%	£917 / kW D £815 / kW C

(*) Learning rates can reduce as a technology matures. This is due to more limited cost reduction potential in an advanced market.

Small wind: projected installed costs for systems to 2050. Large cost reduction in the short term.

- A large reduction in costs is predicted 2005 – 2015. This is due to the introduction of volume manufacture and high growth.
- Reduction in cost becomes less as the market matures circa 2015 – 2050. This is caused by lower learning rates arising from technology maturity.
- These projections are in line with US AWEA targets for 2020*.
- Costs are predicted to approach circa £500 - £900 in 2050



(*) The US Small Wind Turbine Industry Roadmap. AWEA. 2002

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Small wind: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	1.5 kW D 15 kW C	Rated power at 12 m/s.
Lifetime	20 yrs D 25 yrs C	Manufacturers product life*. Lifespan up to 25 years for conventional turbines[#].
Maintenance cost	1.75% cap.	Danish Wind Energy Association figure of 1.5 – 2.0%**.
Load factor	17% D 25% C	Based on 4.5 m/s average annual wind speed in urban environment. This value is obtained by combining the wind speed probability distribution with the wind turbine power output curve[##]. Based on 5.5 m/s average wind speed. 25% is the lower value for large wind provided by BWEA[#].

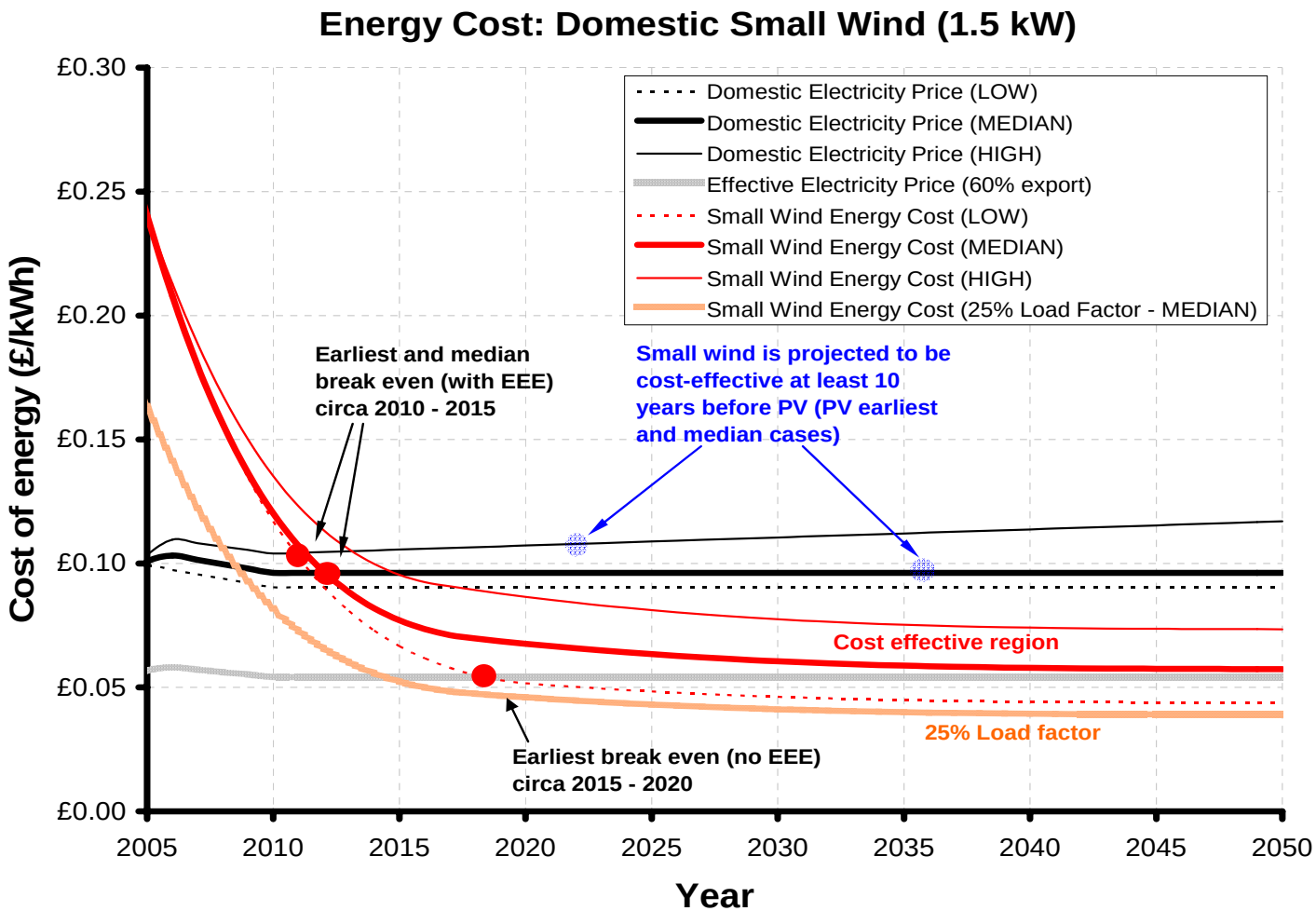
The following base costs are applicable to wind generated electricity:

- Domestic: domestic electricity prices (both with EEE and without EEE)
- Commercial: commercial electricity prices.

(*) UK manufacturers value.
(#) British Wind Energy Association figure. http://www.bwea.org
(**) Operation and Maintenance Costs for Wind Turbines. Danish Wind Energy Association. http://www.windpower.org/en/tour/econ/oandm.htm
(##) Installations at sites with less than 4.5 m/s average wind speeds may be un-economic. However installations at sites higher than 4.5 m/s will be significantly more economic due to much higher load factors. This is because of the cubic windspeed-power output relation.

Domestic small wind: generated energy costs. Break-even predicted 2010 – 2015 (with EEE).

- Break-even for small wind is predicted circa 2010 – 2015.
- EEE is essential for break-even to be achieved under the median case.
- Increased load factors (e.g. location in an area with above-average wind speeds) could advance break even (with EEE) to 2005 – 2010.



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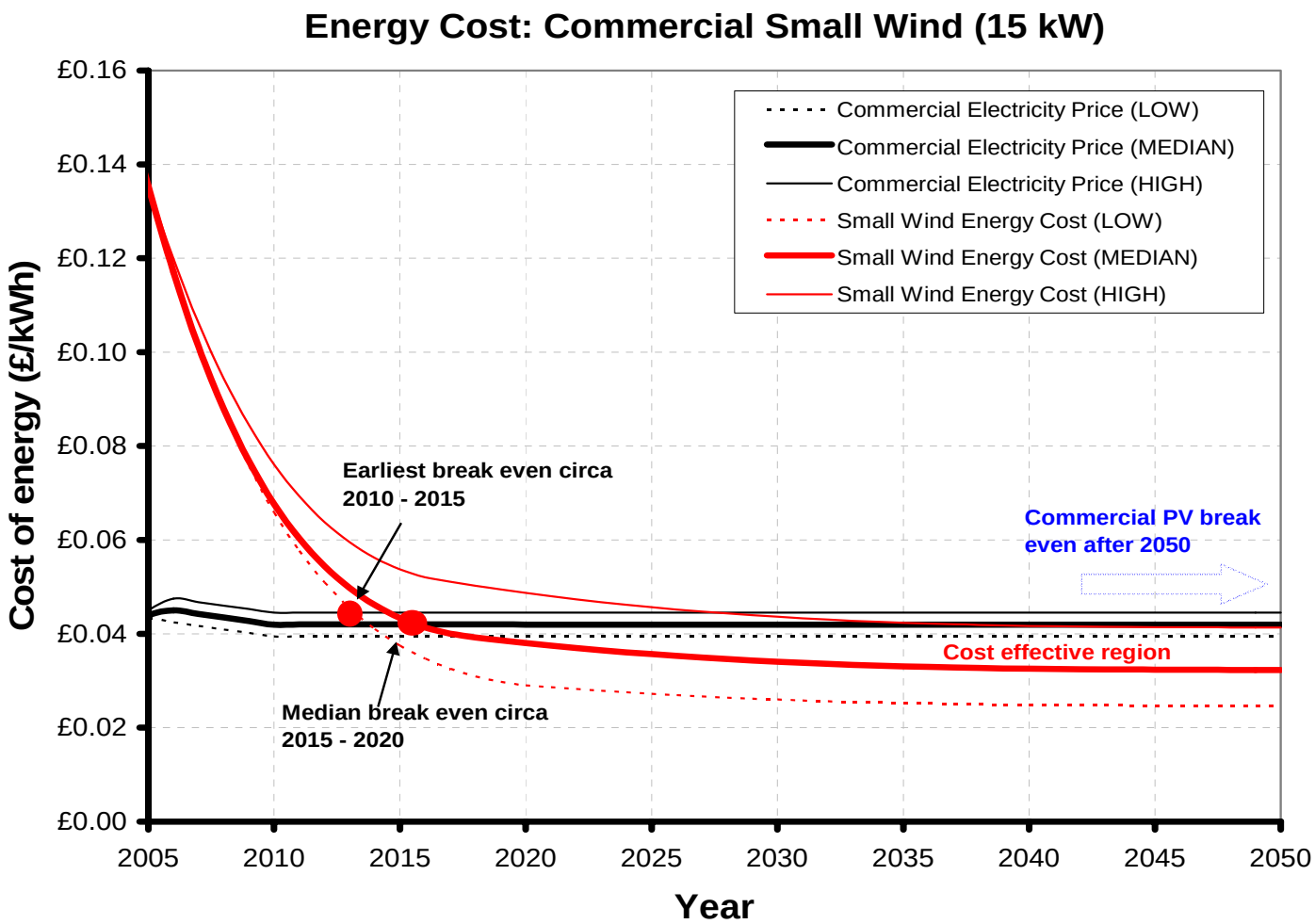
Commercial small wind: generated energy costs. Break-even predicted 2010 – 2020.

- Commercial wind is predicted to break even circa 2010 – 2020.
- The break-even date could be later than for domestic wind because of the lower commercial base costs.



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Micro-hydro : installed capital costs.

- The costs of hydro electric installations varies greatly with the type of system, the installation requirements (such as civil engineering works)*, and the planning and consultation process#.
- The costs here are partially based on the installation of retro-fit systems where some civil works are possibly required but some of the relevant infrastructure is already in place (such as an old water mill site or waterfall).
- Expressing the cost as a function of power is difficult due to turbine power varying with installation conditions (such as water head).

2005 Installed Capital Costs

Small domestic 0.7 kW: £2700 / kW

- This is based on a commercially available small self-contained unit requiring a low-head of water.
- This includes installation and grid connection but excludes significant civil works**.

Large domestic / commercial 10 kW: £2000 / kW

- This system could be used in a large residential or small commercial application, e.g. and old water mill. The system is modelled as a commercial installation, but with electricity export.
- A cost of £2000 / kW was chosen as representative of a typical scheme##.

(*) The cost of a new hydro installation will be significantly greater than for a 'replacement' system (for example, fitting an hydro-electric generator in a previously built weir or old mill). These civil construction costs are difficult to quantify due unique requirements of each installation).

(#) The planning and consultation process for hydro schemes to meet environmental legislation can be long and expensive and pose a barrier to successful implementation. (From discussions with industry).

(**) The turbine cost is approximately £1700 / kW with an estimated additional £1000 / kW for installation and grid connection. Energy Saving Trust figures suggest up to £4000 / kW for small installations.

(##) Costs for 100 kW low head hydro scheme: £1150 - £2800 / kW (A guide to UK mini hydro developments. The British Hydropower Association. 2005). Costs for an 18 – 20 kW scheme: £1500 / kW (from industry consultation 2005).

Micro-hydro: scenarios for projected installed costs to 2050

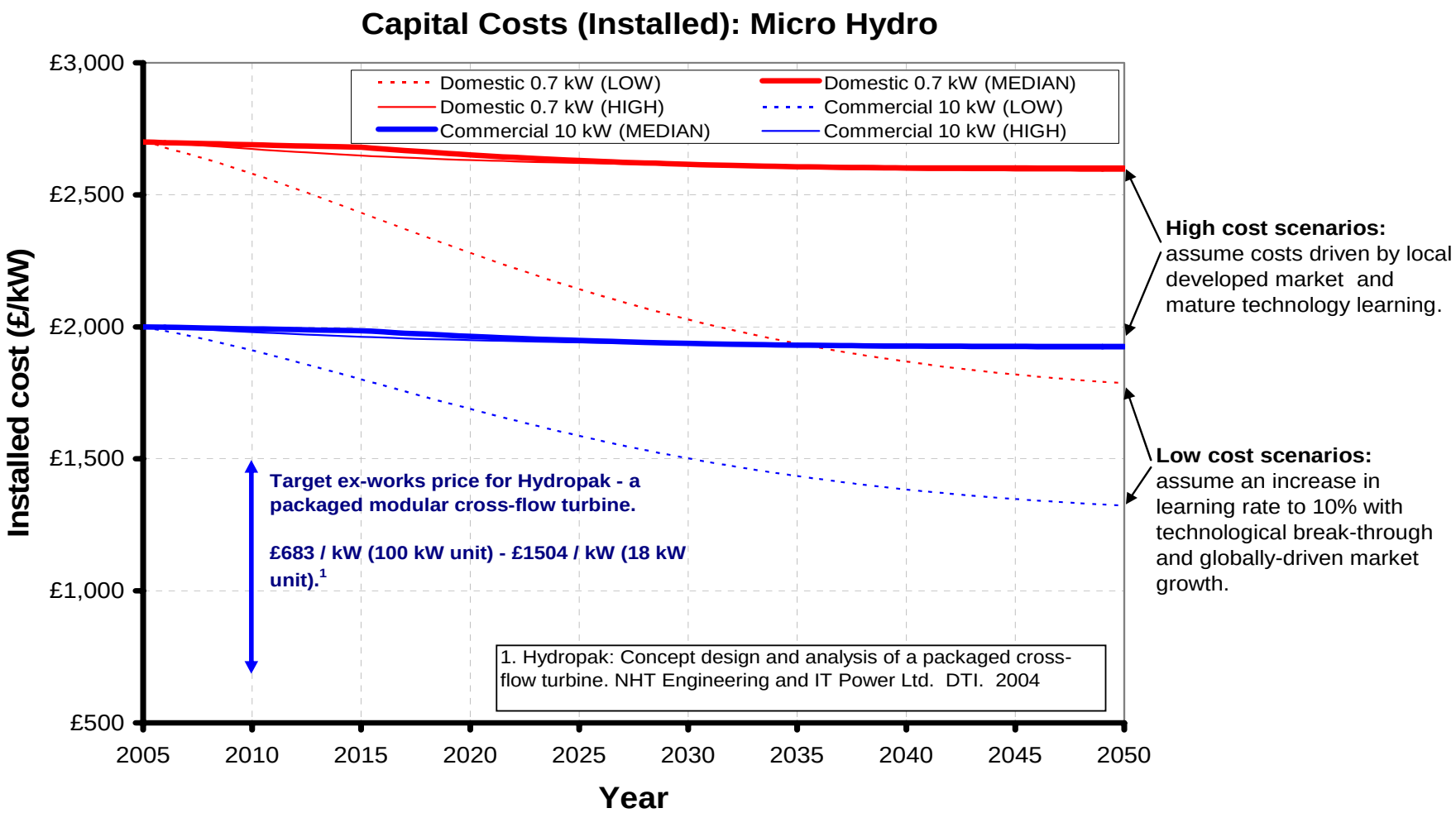
- Hydro generation is a long-established and mature technology leading to a low learning rate of around 1.4%*. Novel micro-hydro systems could have an increased learning rate.
- The hydro market is partially localised with local generator/turbine suppliers and engineering contractors.
- European hydro market is mature#. Developing countries such as China exhibit large growth.
- Three scenarios are created by changing the learning conditions.

Cost Scenario	Learning rate (%)	Growth per annum (%) (2005 value)	2050 Cost (£/kW)
Low	10% *(represents technological breakthrough at global scale)*	16% *(high growth in expanding market – e.g China)*	£1787 / kW D £1323 / kW C
Median	1.4% *(low value due to technology maturity and local market)*	5% *(median growth – estimate)*	£2598 / kW D £1924 / kW C
High	1.4% *(low value due to technology maturity and local market)*	1% *(low growth in mature market such as Europe)*	£2608 / kW D £1932 / kW C

(*) 1.4 % obtained from : Learning curves and Technology Assessment. McDonald A and Schrattenholzer L. International Journal of Technology management. 2002. This is based on large and small hydro, although the technology basis is similar.

(#) 82% of EU economic potential for small hydro (<10 MW) already achieved (source - "Small Hydro - Runaway Potential", Renewable energy world, Jul-Aug 2005 Vol. 8, No. 4. pp 248.) This can be taken as the high cost scenario due to the inclusion of larger scale systems.

Micro-hydro: projected installed costs for systems to 2050.



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Micro-hydro : technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	0.7 kW D 10 kW C	Small 'drop-in' unit requiring minimal installation. Suitable for retro-fit at an old mill.
Lifetime	20 yrs D 50 yrs C	Estimate*. British Hydropower Association#.
Maintenance cost	3%	U.S. figure**.
Load factor	50%	The load factor is relatively high due to the stability of water flow in rivers and streams. British Hydropower Association figure#.

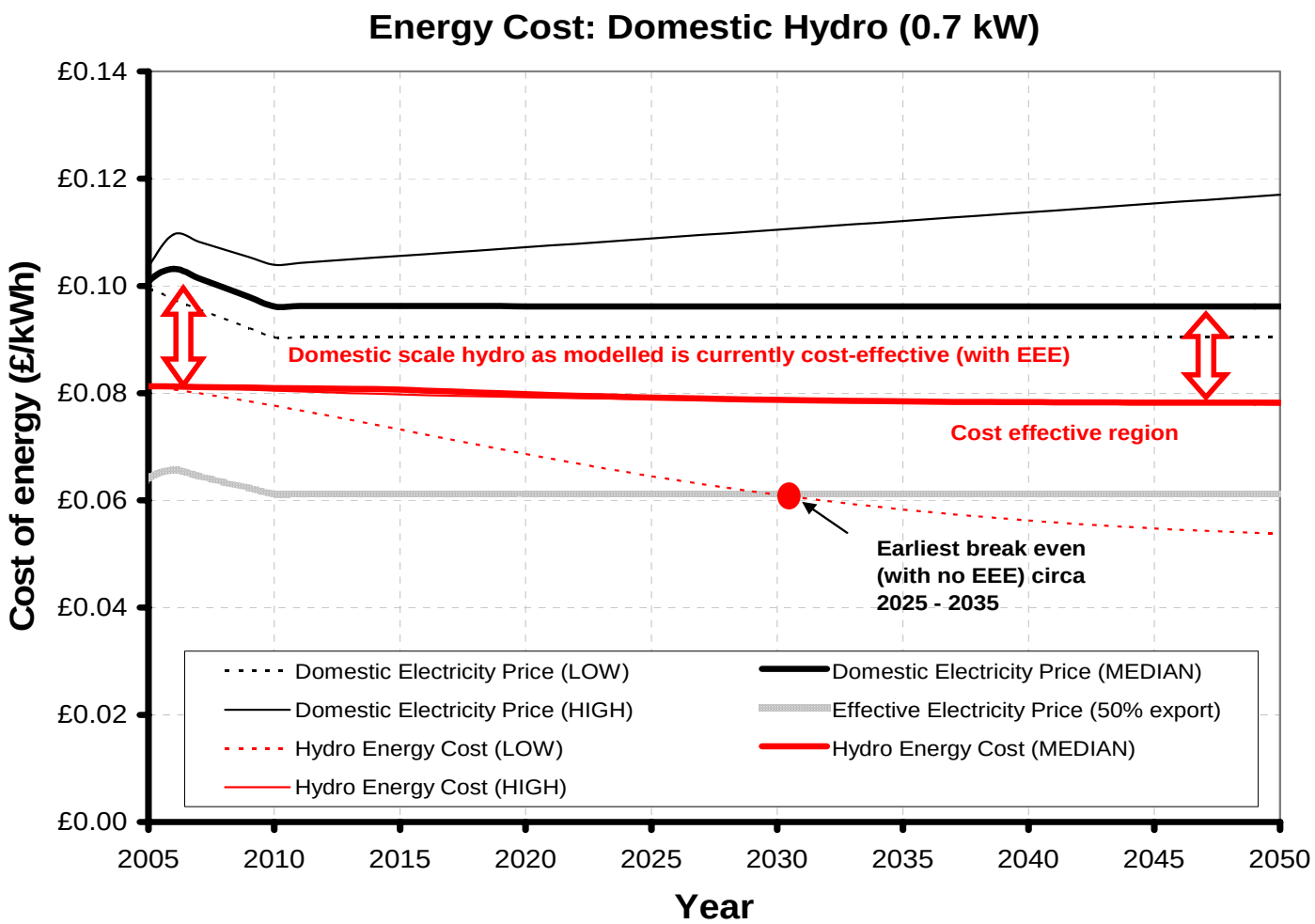
The following base costs are applicable to hydro generated electricity:

- Domestic: domestic electricity prices (both with EEE and without EEE)
- Commercial: commercial electricity prices (both with EEE and without EEE)

(*) The lifespan of smaller drop-in units is significantly less than more heavily engineered larger installations. (Industry contact).
(#) A guide to UK mini hydro developments. The British Hydropower Association. 2005.
(**) Renewable Energy for Microenterprise. NREL. 2000.

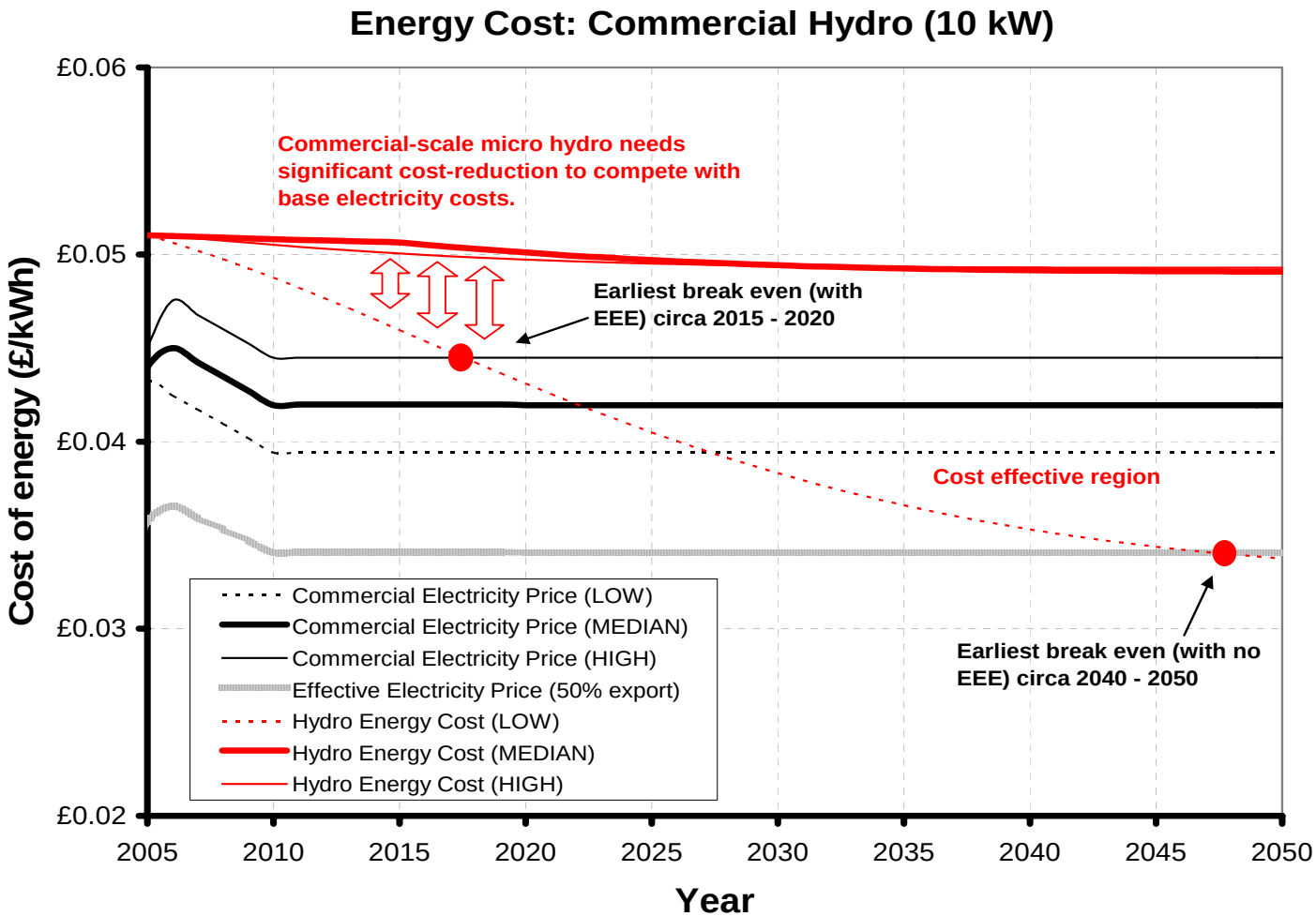
Micro-hydro 0.7 kW: generated energy costs. Significant cost reduction required for non-EEE break-even.

- The system as modelled is currently cost effective (with EEE).
- If additional civil-engineering costs are required, then the installation may not be economic.
- Break-even with no EEE requires significant capital cost reductions.
- With localised growth and no technology advances, the costs are predicted to remain fairly stable.



Micro-hydro : generated energy costs. Significant cost reduction required for EEE break-even by 2015 – 2020.

- Cost-effectiveness is not achieved under the median scenario.
- Significant capital cost reductions are required. This requires technology improvements and globalisation, and possibly reduced planning and consultation costs*.
- Non-EEE is predicted to delay the low cost break-even by around 30 years.



(*) Up to 10 % of capital costs can be due to planning and legislation issues (Industry contact).

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Contents

Solar water heating: installed capital costs.

2005 Installed Capital Costs

Domestic 2.8 kW glazed or evacuated tube system: £1600 / kW

- 2.8 kW size based on a 4 m^2 system producing 0.7 kW / m^2*.
- The Energy Saving Trust data suggests costs of £3500 - £4500 for systems 2 – 4 m^2.
- A 4 m^2 system costing £4500 gives a unit cost of approximately £1600 / kW using the IEA power conversion factor.

(*) The conversion of 0.7 kW / m^2 is provided by the International Energy Agency for standardising solar heating calculations. Location in the UK is accounted for by using a capacity factor based on solar radiation.

Solar water heating: scenarios for projected installed costs to 2050.

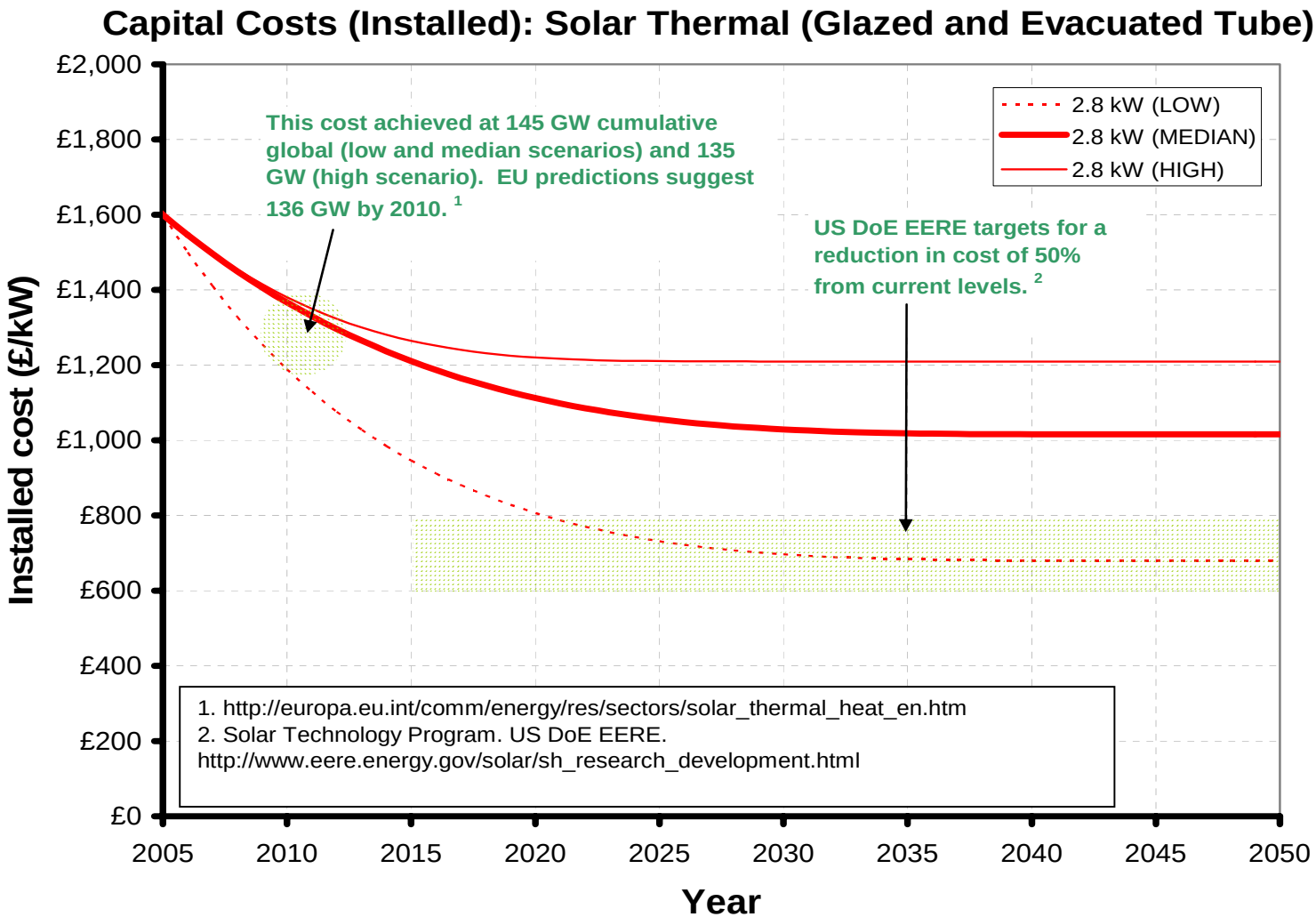
- Global model based on current growth 23% year on year*.
- A learning rate of 10% is modelled for the median scenario. This relatively low value reflects the mature nature of the technology.
- Cost scenarios are created by changing the learning rate and rate of change of market growth.

Cost Scenario	Learning rate (%)	Rate of change in annual growth per annum (% p.a.)	2050 Cost (£/kW)
Low	18% *(represents increased cost reduction potential)*#	-1.5% change per annum *(from initial growth rate of 23% p.a)*	£680 / kW
Median	10%	-1.5% change per annum *(from initial growth rate of 23% p.a)*	£1015 / kW
High	10%	-3% change per annum *(represents a smaller market)*	£1209 / kW

(*) This is the average annual growth for glazed collectors 1999 – 2004. Based on data from: Solar Heating Worldwide – Markets and Contribution to the Energy Supply 2003. IEA. 2005.

(#) The value of 18 % is suggested in Experience Curves for Energy Technology Policy. IEA. 2000. However this is based on using 18 % as the average learning value for a large range of technologies. The wide range of solar heating system types makes defining a learning rate for a single type difficult.

Solar water heating: projected installed costs for systems to 2050.



Solar water heating: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	2.8 kW	Based on 4 m^2 system at 0.7 kW / m^2.
Lifetime	15 yrs	Manufacturers warranty.
Maintenance cost	2%	Maintenance requirements should be minimal. However, individual tubes may need replacing during the lifetime.
Load factor	13%	This value is based on 1000 kWh/m^2 per year solar radiation but is highly variable depending on geographic location and positioning of panels*.

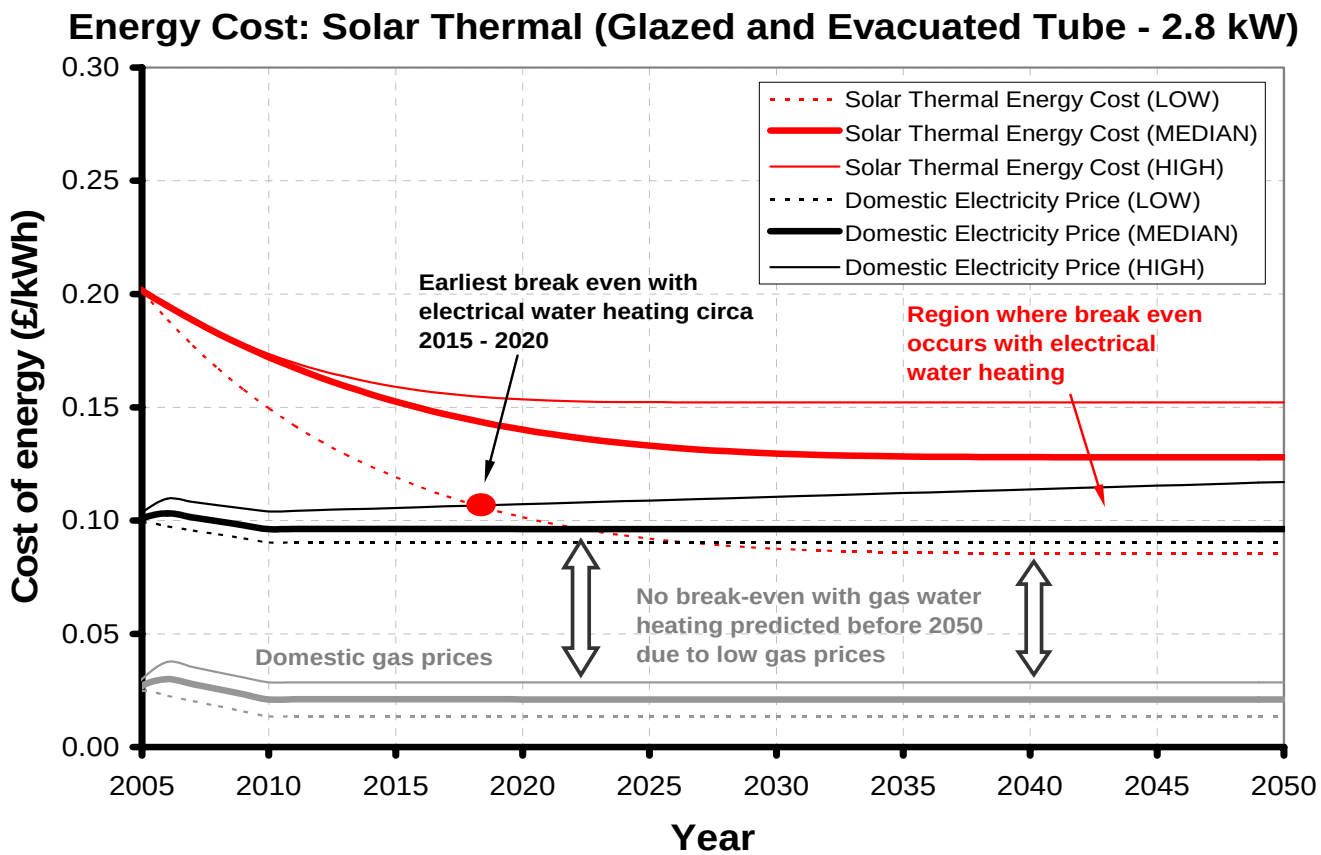
The following base costs are applicable to solar water heating:

- Domestic gas cost (no boiler system is included: the solar water heating only replaces the gas consumed for water heating) and domestic electricity cost (for electrical water heating comparison - standard tariff).

(*) Sizing and calculating solar heating systems in terms of kW requires the use of the 0.7 kW / m^2 IEA conversion factor which itself is based on a number of assumptions. Therefore other values such as capacity factor should be taken as representative and not absolute.

Solar water heating: Large reductions in generated energy cost are required for break even with electrical water heating.

- Break-even is not predicted for gas (or oil) boiler water heating. This is because of high capital costs combined with low oil and gas prices.
- Approximately 50 % capital cost reduction is necessary for break-even with electrical water heating by 2015 – 2020.



Biomass heating: installed capital costs and scenarios.

2005 Installed Capital Costs

Domestic 20 kW biomass boiler: £5000

- The Energy Saving Trust suggests a typical installed cost of £5000.
- Based on a 20 kW boiler for central heating and water heating in a typical 3-bed semi-detached house*.

Scenarios

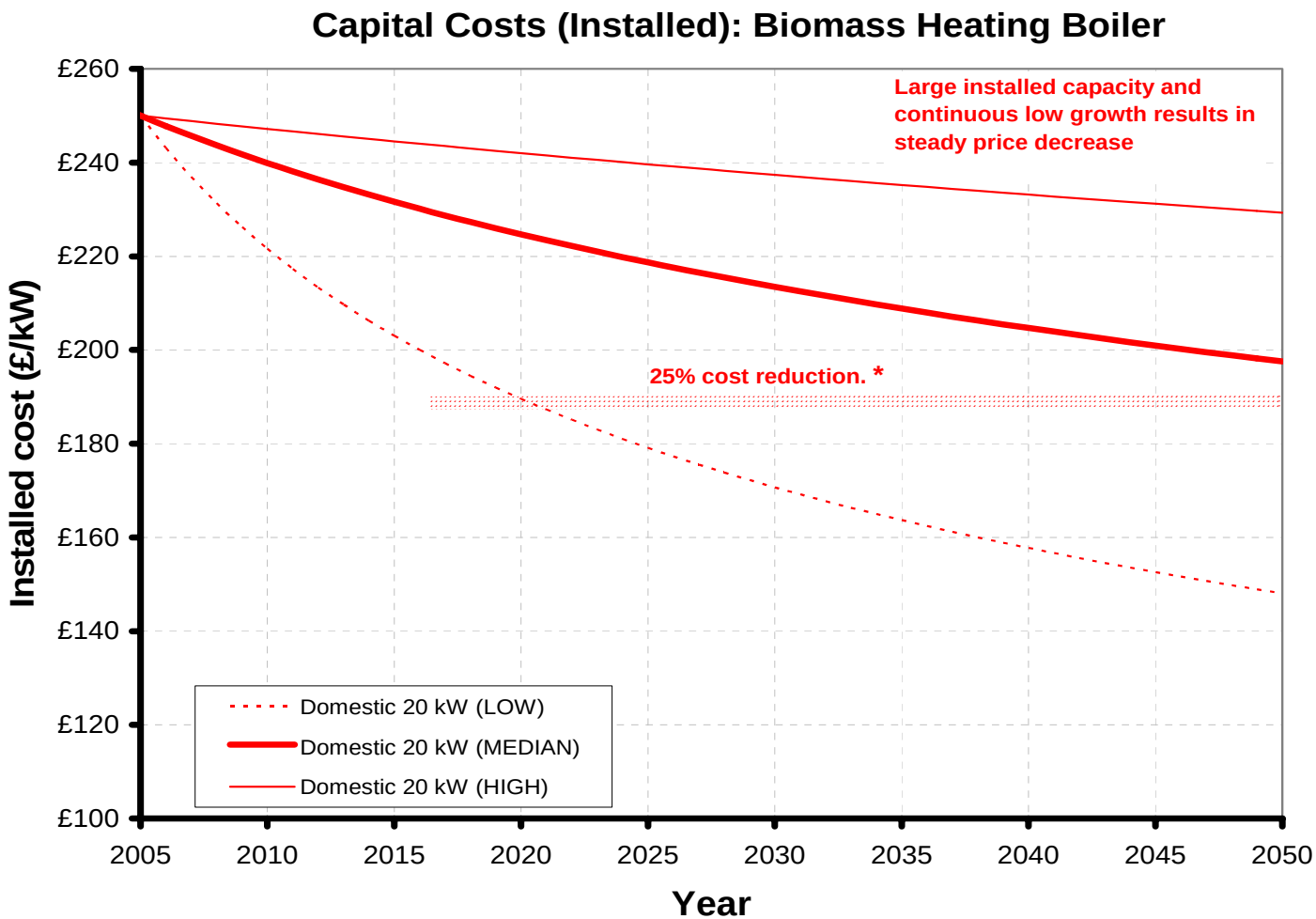
- Learning is based on 15 % median# and a low cost scenario of 20 %.
- Growth conditions are modelled to provide approximately 25% reduction in boiler cost**.

Cost Scenario	Learning rate (%)	Growth conditions	2050 Cost (£/kW)
Low	*20% (represents increased cost reduction potential)*	Large cumulative capacity. High installations p.a.	£148 / kW
Median	15%	Large cumulative capacity. Median installations p.a.	£198 / kW
High	15%	Large cumulative capacity. Low installations p.a	£229 / kW

(*) This is designed as a replacement for gas and oil central heating boilers.
(#) 15 % is provided for biomass electricity generation: Experience Curves for Energy Technology Policy. IEA. 2000.
(**) This value is given as the overall potential for cost reduction in: Possible support mechanisms for biomass-generated heat. Ilex Energy Consulting. 2003.

Biomass heating: projected installed costs for systems to 2050.

- Biomass boilers are projected to decrease in price by around 25% through improvements in technology and installation experience.
- A steady reduction in cost to 2050 is predicted in line with cumulative capacity increases.



(*) Possible support mechanisms for biomass-generated heat. Ilex Energy Consulting. 2003.

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Biomass heating: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	20 kW	Suitable for a 3-bed semi detached house.
Lifetime	20 yrs	Based on manufacturers data*.
Maintenance cost	3%	Estimate#.
Load factor	10%	This was based on medium domestic space heating requirements of 17.5 MWh p.a.
Efficiency	90%	Manufacturers figure.

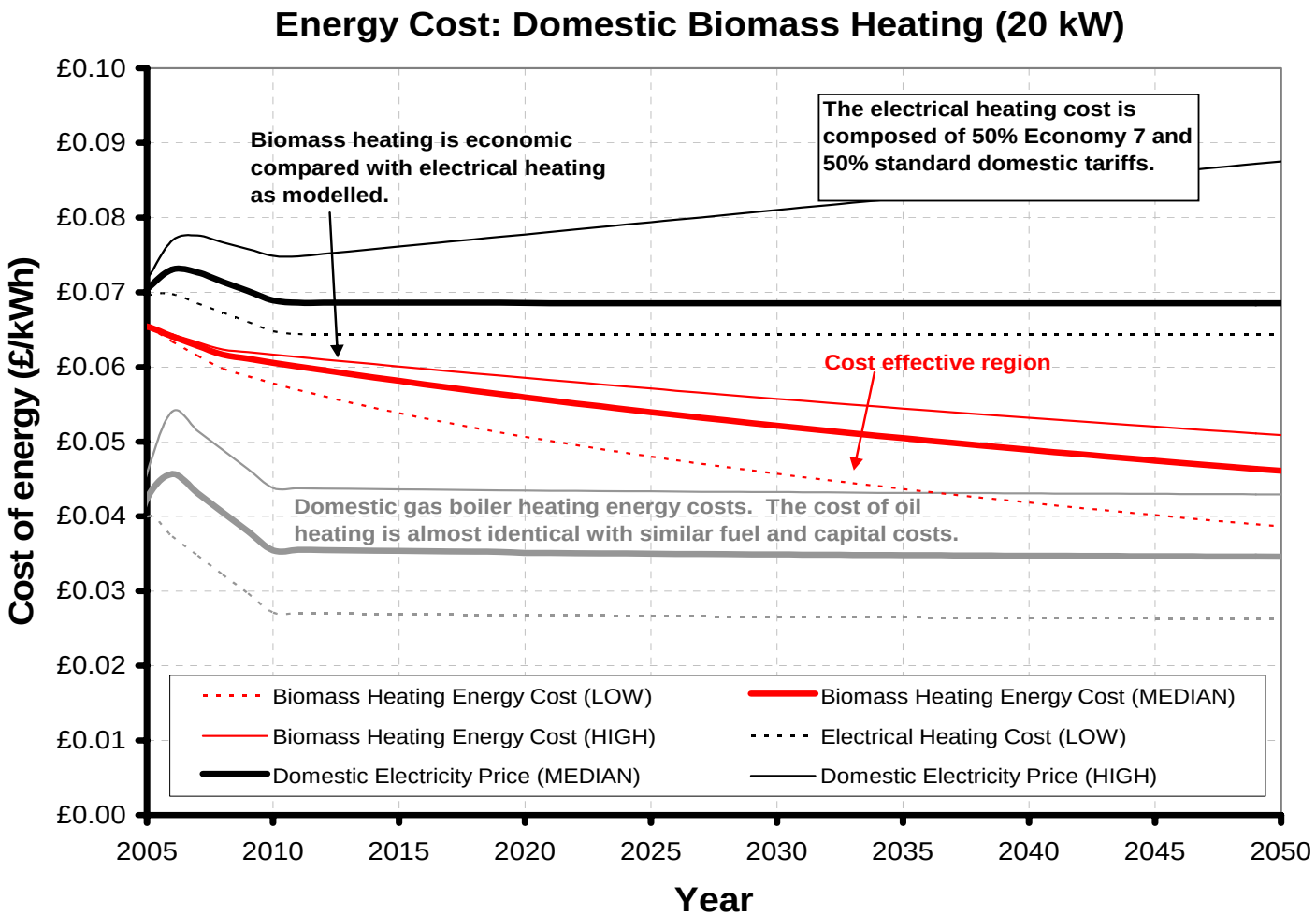
The following base costs are applicable to biomass heating:

- Domestic gas heating and electrical heating (composed 50% Economy 7 and 50% standard tariff**).

(*) A 20 year lifetime is typical of the smaller biomass boilers. This increases for larger systems.
(#) The additional complexities of Biomass systems such as automatic fuel feed systems could cause higher maintenance costs than for conventional gas boilers.
(**) The 50% mix of Economy 7 and standard electricity is chosen to reflect low cost heating at night and daytime space and water-heating requirements.

Biomass heating: biomass can be cost-effective as a replacement for electrical heating.

- Biomass boilers are currently cost effective with electrical heating as modelled*.
- Large reductions in capital cost are necessary for predicted break-even by 2050 with gas (or oil) heating.



(*) This analysis only considers the boiler cost and not heating system. The additional costs of installing a wet-heating system as electrical heating replacement could make the biomass installation un-economic. The difference for new-build could be less, but water heating systems are typically more expensive than electrical heating.

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Ground source heat pumps (GSHP): installed capital costs.

2005 Installed Capital Costs

Domestic 5 kW GSHP: £900 / kW

- The cost of GSHP installations can heavily depend on the installation of the ground pipe loops e.g. surface loops in a new-build installation could be less expensive than vertical bore-hole loops in an existing dwelling.
- Domestic systems (including ground loops) cost £400 - £450 / kW before installation*.
- This installed cost can rise to £1100 / kW#.
- £900 / kW has been chosen to reflect the potential high installed costs whilst allowing for reduction through installations in new-build properties.
- A 5 kW unit is modelled for providing the space-heating requirements for a medium demand house.

(*) A 10 kW cost of £4000 - £4500 was quoted by a UK manufacturer for a kit comprising the heat pump, slinky ground coil, manifolds and other associated equipment.

(#) This value is used by a UK installer for estimations. Based on a 5 kW thermal output.

GSHP: scenarios for projected installed costs to 2050.

- Strong growth in certain European countries with an average value of 17% calculated for Austria, Sweden and Germany*. However the suitability of ground-source heat pumps can vary with climate.
- The learning rate for heat pumps is considered to be near the value for air-conditioning units due to the technological similarities#.

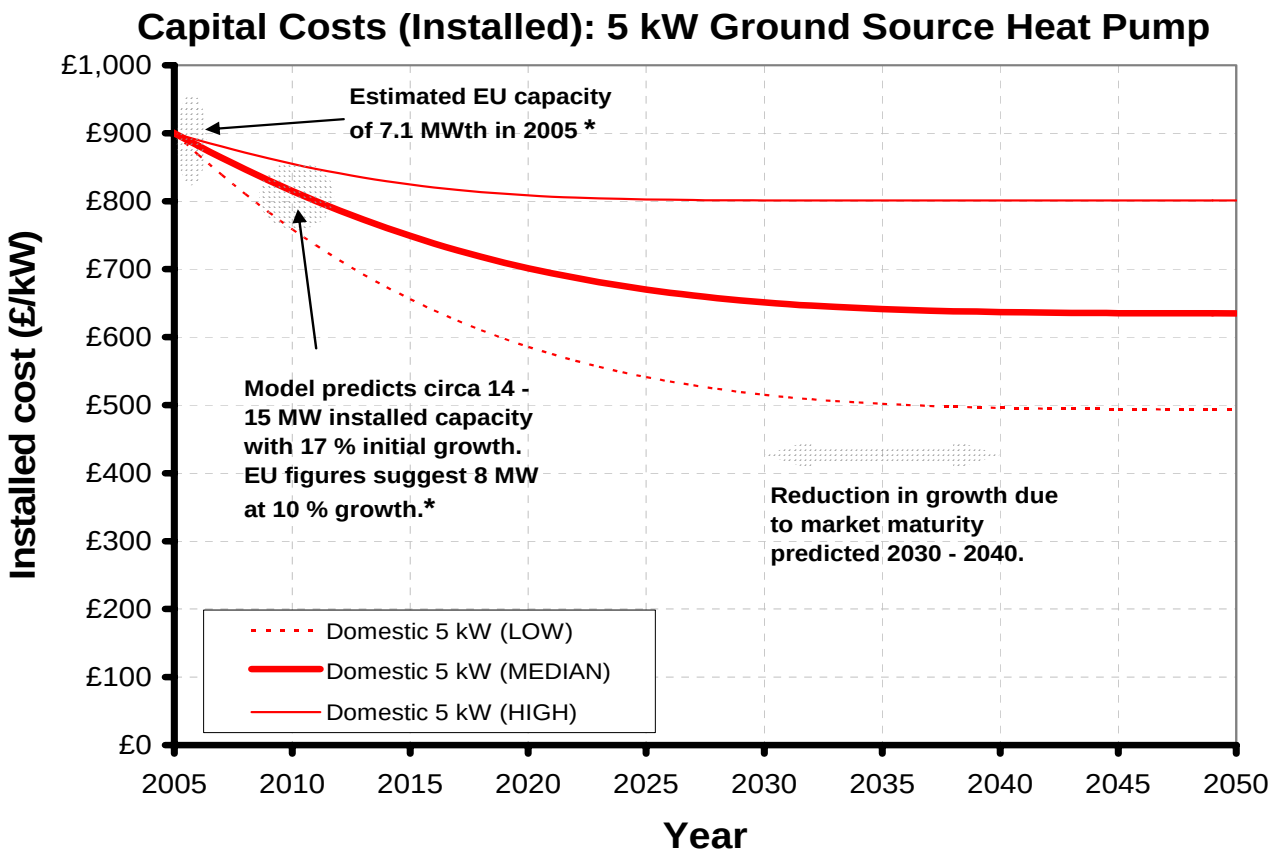
Cost Scenario	Learning rate (%)	Rate of change in annual growth per annum (% p.a.)	2050 Cost (£/kW)
Low	15% *(represents increased cost reduction potential)*	-1% change per annum *(from initial growth rate of 17% p.a)*	£494 / kW
Median	9% *(based on similar technologies)*#	-1% change per annum *(from initial growth rate of 17% p.a)*	£635 / kW
High	5% *(reduction in learning with technology maturity)*	-2% change per annum *(represents a smaller market)*	£801 / kW

(*) This is the average growth for the period 1998 – 2004. Data obtained from IEA Heat Pump Newsletters Vol. 22, No. 2/2004 and Vol. 23, No. 2/2005.

(#) 10 % learning rate for Japanese air conditioners 1972 - 1997. From: Learning curves and Technology Assessment. McDonald A and Schrattenholzer L. International Journal of Technology management. 2002. The learning rate for GSHP could be lower due to additional installation requirements with smaller scope for cost reduction.

GSHP: projected installed costs for systems to 2050.

- There is limited cost reduction predicated for GSHP systems due to large installed capacity (2005) and relatively low learning rate.
- A large proportion of costs are due to installation. These could be reduced by improvements to industry network (approved installers etc) but ground-work costs for surface and bore-hole loops will remain.



(*) EU predictions. http://europa.eu.int/comm/energy/res/sectors/geothermal_energy_en.htm

GSHP: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	5 kW	This is a typical size system for a single residential application with 30% capacity factor*.
Lifetime	20 yrs	Heat pump lifetime is 15 – 20 years, but ground loops can last 50 years#.
Maintenance cost	5%	This is an estimate based on an annual maintenance check#.
Load factor	30%	This was based on domestic space heating requirements and best practice case study#. Produces 13.1 MWth per annum – sufficient to heat a medium demand house.
Coefficient of performance	3.16	Taken from case study#. A value of 2.8 is suggested as competitive against electrical heating**.

Energy input

- The GSHP system is modelled with an electricity input of 50% Economy 7 and 50% standard tariff ##.

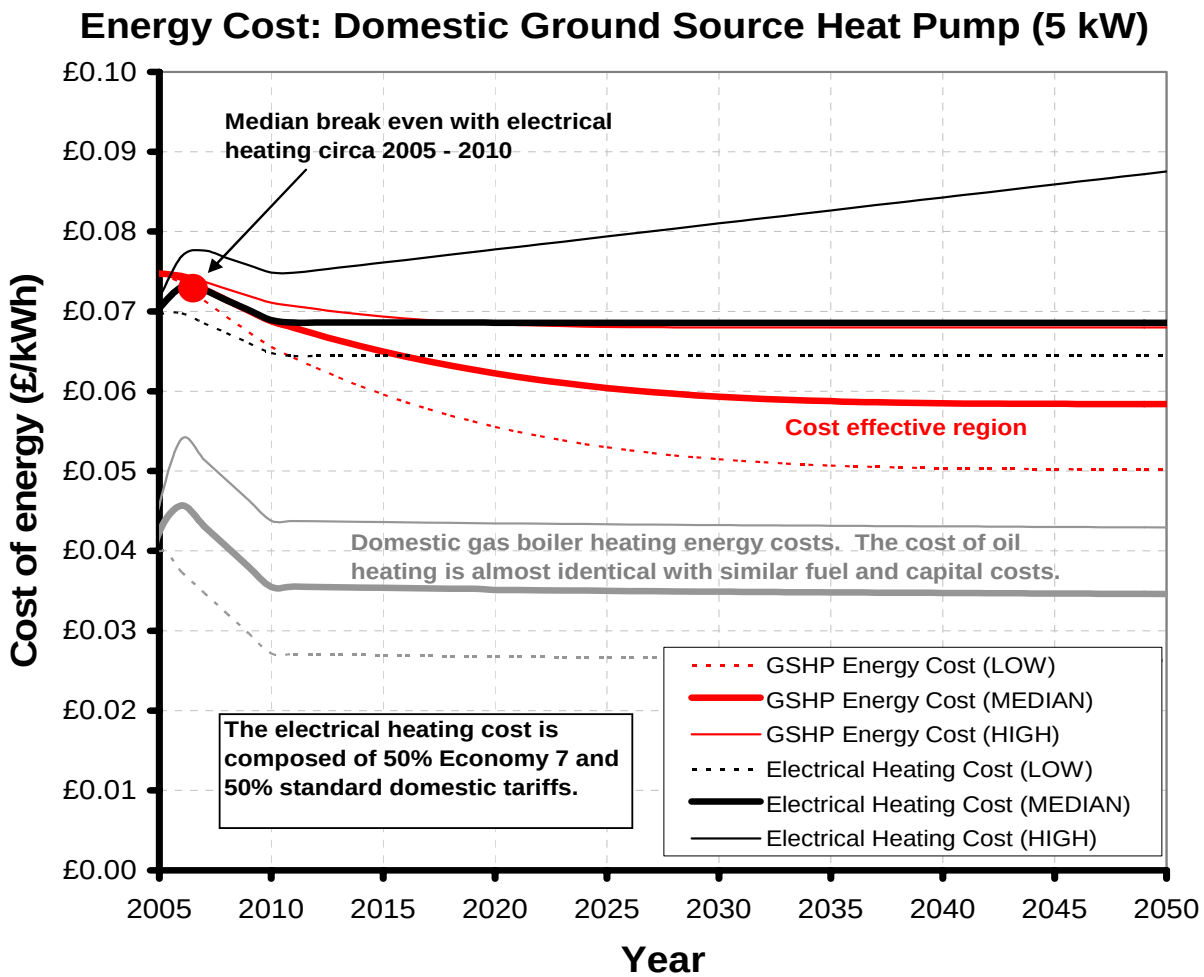
The following base costs are applicable GSHP heating:

- Domestic gas and oil boiler heating and electrical heating (composed 50% Economy 7 and 50% standard tariff ##.

(*) Sizing information obtained from UK installer.
(#) GIR 72 – Heat Pumps in the UK: a monitoring report. Energy Efficiency Best Practice Programme. 2000.
(**) GIR 67 – Heat Pumps in the UK: current status and activities. Energy Efficiency Best Practice Programme. 2000.
(##) The 50% mix of Economy 7 and standard electricity as chosen to reflect low cost heating at night and daytime space and water-heating requirements.

GSHP: generated energy costs. Break-even with electrical heating predicted 2005 – 2010.

- GSHP could become cost-effective with electrical heating by 2005 – 2010.
- Break-even is not predicted with oil and gas heating.
- The installed costs for GSHP as a replacement for electrical heating are likely to be higher. This would delay the break-even date*.



(*) This analysis only considers the boiler cost and not heating system. The additional costs of installing a wet-heating system as electrical heating replacement could make the GSHP installation un-economic. The difference for new-build could be less, but water heating systems are typically more expensive than electrical heating.

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Contents

Combined heat and power system modelling.

Three different types of CHP system are modelled:

1. Small domestic Stirling engine CHP.
2. Reciprocating engine CHP (both domestic and commercial).
3. Solid oxide fuel cells (SOFC).

The added complexity of combined heat and power generation requires some modifications to the cost-of-energy model:

- **Capital costs for CHP systems**
  - CHP capital costs are expressed in terms of their electrical capacity, **£/kWe.**
  - The heat output is linked to the electrical capacity by the heat-to-power ratio.

- **Hybridised base costs:**
  - The combined base cost for CHP is hybridised using the output heat to power ratio.
  - For example with 33% electrical capacity* and 67% thermal capacity:

Combined base cost / kWh = 0.33 × (effective electricity price / kWhe) + 0.67 × (replaced heating price / kWhth)

(*) The electricity price used in the hybridised costs can be grid electricity (with EEE / no export), or the effective electricity cost when exporting with a non-EEE arrangement.

Analysing the cost-effectiveness of CHP operation.

Calculating the cost of energy

- The energy costs are expressed as a hybridised value, calculated by dividing the total investment costs per annum (annualised capital costs + fuel cost) by the total energy produced (the sum of electrical and thermal): £ / kWh_{total}
- CHP technologies are modelled operating in 100% CHP mode. This ignores periods of time when the unit may operate in heating mode only.
- To account for 100% CHP mode operation, calculations use the “on-cost” of the CHP system (i.e. the additional price over the replaced heating boiler). This on-cost is the price paid for the CHP capability.
- To remain consistent, for CHP the baseline energy cost is modified (e.g. gas-boiler heating cost per kWh) by removing the boiler capital cost from the cost of energy calculations.

CHP load factor

- The load factors are based on the average energy demand values from a typical system per annum*.
- The systems are sized for operation in their optimum regime with different building types. E.g. a high heat-to-power ratio system has a high thermal output and is suitable for a larger or less well insulated property, whilst a low heat-to-power ratio system is more suitable for a smaller heating demand.

(*) These values are based on Element Energy experience of CHP system modelling and sizing for residential and commercial installations.

Stirling and reciprocating engine CHP: installed capital costs.

2005 Installed Capital Costs

Domestic 1.2 kWe (8 kWth) Stirling CHP: £2080 / kWe

- This is sized for supplying a large fraction of a typical domestic electricity demand and a thermal capacity for high heating demand.
- The installed price for a 1.2 kWe domestic Stirling CHP system in the UK is currently £2500, giving £2080 / kWe*.

Small recip. engine CHP 5.5 kWe (12.5 kWth): £2180 / kWe

- A system of this size is suitable for multiple residences with relatively low thermal demand and high electrical demand applications, e.g. a small well insulated block of flats.
- The installed cost for a 5.5 kW domestic IC engine CHP in late 2004 was £12,000 giving a unit cost of £2180 / kWe#.

Large recip. engine CHP 33.3 kWe (50 kWth): £950 / kWe

- This system is sized for multiple residential or commercial application.
- The cost is based on 2001 data for recip-based CHP costs as a function of electrical capacity**.

(*) Powergen figure for individual domestic installation. 2005.
(#) Case study in “Micro-CHP Fact sheet: United Kingdom”. COGEN Europe. 2005.
(**) Adoption and diffusion of de-centralised energy conversion technologies: the success of engine co-generation in Germany. Madlener R and Schmid C. Energy and Environment, Vol. 14, No. 5, 2003.

Stirling CHP: scenarios for projected installed costs to 2050.

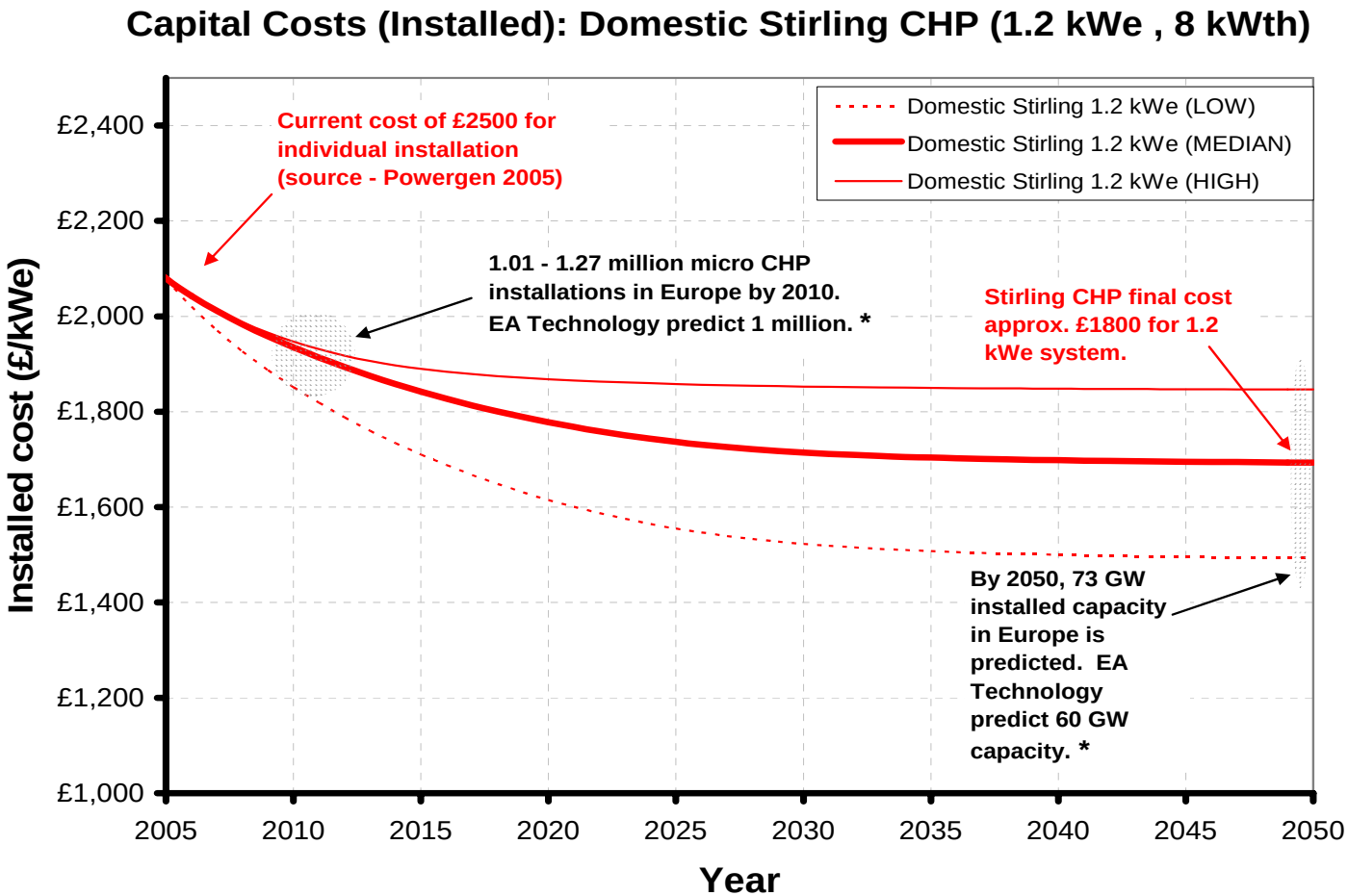
- The market for domestic Stirling CHP units is immature, but with a high start-up growth.
- There is some potential for future reduction of on-cost.
- Three scenarios are created by changing the learning rate and growth change.

Cost scenario	Rate of change in annual growth per annum (% p.a.)	Learning rate (%)	2050 Cost* (£/kWe)
Low	-2% change per annum *(from initial growth rate of 40 % p.a.)*	4% *(represents a greater potential for cost production)*	£1493 / kW
Median	-2% change per annum *(from initial growth rate of 40% p.a.)*	2.5% *(low value due to maturity and simplicity of technology)*	£1693 / kW
High	-5% change per annum *(the annual growth reduces more quickly)*	2.5% *(low value due to maturity and simplicity of technology)*	£1847 / kW

(*) These are the prices for the complete system per kW electrical capacity. To obtain a system price for different sizes, the CHP on-cost must first be calculated and multiplied by the electrical capacity, and then added to the appropriate replaced boiler cost.

Stirling CHP: projected installed costs for systems to 2050.

- The micro-CHP growth model scaled to a European market is consistent with other projections for 2010 and 2050*.
- A final median cost of £1800 is predicted for a 1.2 kWe Stirling CHP system*.
- This represents an on-cost of about £600 compared with a domestic boiler.
- The requirement for an additional on-cost limits the overall potential for reduction.



(*) Micro CHP in Europe. Harrison. EA Technology. 2003.

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Stirling CHP: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

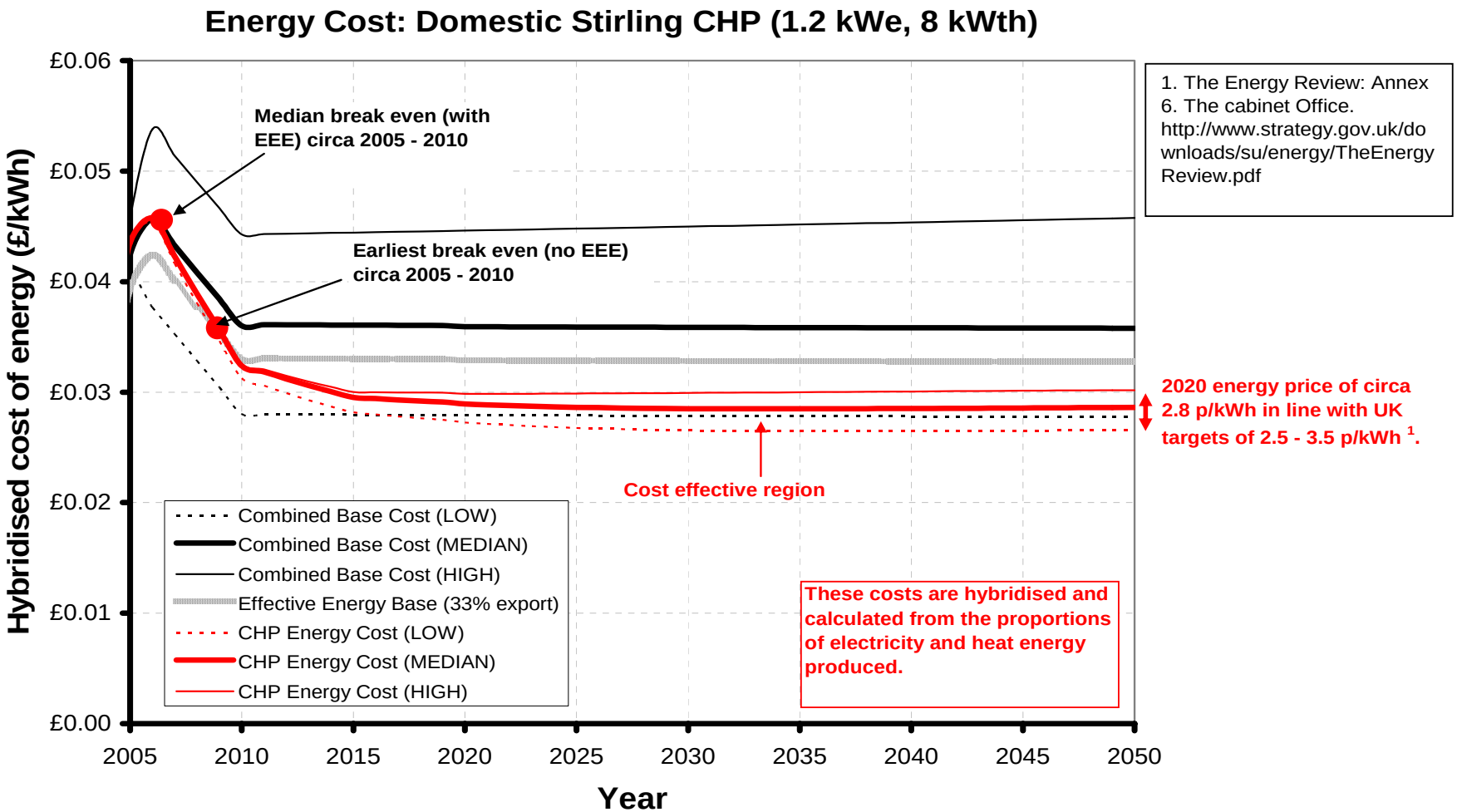
Parameter	Value	Notes
Rated power	1.2 kWe 8 kWth	Stirling CHP is suitable for large heating demand applications, e.g, large or less well insulated homes*.
Lifetime	10 yrs (2005) - 15 yrs (2015)	With technology maturity, the lifetime is projected to increase to meet the current lifetime of 15 years for gas boilers.
Maintenance cost	20% (2005) reducing to 9% (2015)	Current high maintenance costs will reduce with technology maturity and experience. The 9% value represents a higher cost than boilers due to the increased system complexity and functionality.
Load factor	30%	A 30% load factor produces 21 MWh thermal energy p.a. – this is suitable for higher heating demands. A smaller value is less economical and heating is typically not required for more than 30% of the time#.

The following base costs are applicable to Stirling CHP generated energy:

- Hybridised base costs using domestic electricity and gas heating prices and electricity export sale price.

(*) These are based on specifications for commercially available Stirling engine CHP systems.
(#) 30% is the optimum load factor for a heat-led CHP system in a domestic environment based on our CHP modelling experience.

Stirling CHP: generated energy costs. Break-even predicted 2005 – 2010.



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Stirling CHP: generated energy costs. Comments.

- Break-even is predicted 2005 – 2010. The generated energy cost from Stirling CHP systems operating at a 30% load factor is currently very close to the hybridised base cost.
- Reductions in the capital cost and maintenance cost combined with increases in the lifetime enable early break-even.
- When electricity is exported (33% for CHP)* the absence of energy export equivalence (EEE) could delay the break-even point by up to 5 years. This is due to the excess exported electricity being sold for less than the price for consumed electricity.
- These points apply to the Stirling CHP system operating in a 30% load factor in situations where the heating demand is large compared to the electrical demand. Inappropriate sizing of systems could increase the cost of generated energy by lowering the load factor. The fraction of electricity exported will also depend on the particular installation and could reduce the cost-effectiveness if no EEE is present.

(*) Data taken from Metering, Settlement, and Export Reward – Options for Micro-generation. Ilex Energy Consulting. DTI. 2005.

Small (5.5 kWe) reciprocating engine CHP: scenarios for projected installed costs to 2050.

- The market for small reciprocating engine CHP units is immature, but with a high start-up growth.
- Learning rates are low due to the mature internal combustion reciprocating engine technology. The on-cost of small recip. CHP is relatively low at present suggesting limited potential for future reductions.
- Three scenarios are created by changing the learning rate and growth change.

Cost scenario	Rate of change in annual growth per annum (% p.a.)	Learning rate (%)	2050 Cost* (£/kWe)
Low	-2% change per annum *(from initial growth rate of 40% p.a.)*[#]	3.5% *(represents a greater potential for cost production)*	£1632 / kW
Median	-2% change per annum *(from initial growth rate of 40% p.a.)*[#]	2.5% *(low value due to maturity and simplicity of technology)*	£1775 / kW
High	-4% change per annum *(the annual growth reduces more quickly)*	2.5% *(low value due to maturity and simplicity of technology)*	£1906 / kW

(*) These are the prices for the complete system per kW electrical capacity. To obtain a system price for different sizes, the CHP on-cost must first be calculated and multiplied by the electrical capacity, and added to the appropriate replaced boiler cost.

(#) 40% initial growth is an estimate.

Large (33.3 kWe) reciprocating engine CHP: scenarios for projected installed costs to 2050.

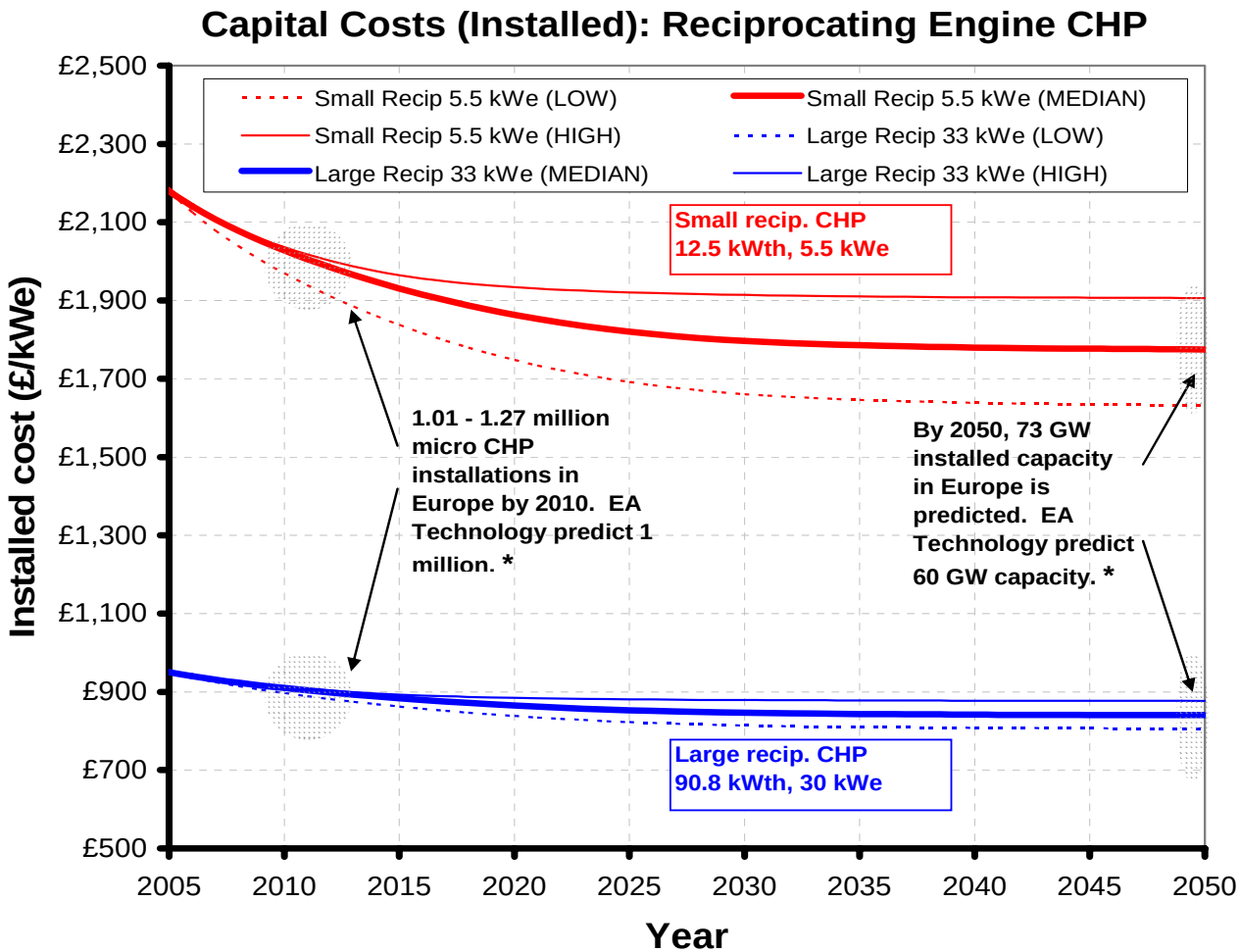
- Market growth for large reciprocating engine CHP units is modelled similarly to small recip. CHP systems.
- Learning rates are very low due to the mature internal combustion reciprocating engine technology and large production volume in this size range.

Cost scenario	Rate of change in annual growth per annum (% p.a.)	Learning rate (%)	2050 Cost* (£/kWe)
Low	-2% change per annum	2% *(represents a greater potential for cost production)*	£806 / kW
Median	-2% change per annum	1.5% *(low value due to maturity and simplicity of technology)*	£840 / kW
High	-4% change per annum *(the annual growth reduces more quickly)*	1.5% *(low value due to maturity and simplicity of technology)*	£877 / kW

(*) These are the prices for the complete system per kW electrical capacity. To obtain a system price for different sizes, the CHP on-cost must first be calculated and multiplied by the electrical capacity, and added to the appropriate replaced boiler cost.

Reciprocating engine CHP: Limited potential for reduction in installed costs for systems to 2050.

- The micro-CHP growth model scaled to a European market is consistent with other projections for 2010 and 2050*.
- There is a greater reduction in costs for small recip. CHP systems due to their higher learning rates.
- A relatively small cost reduction is predicted for larger recip. CHP systems due to the maturity of internal combustion engine technology.



(*) Micro CHP in Europe. Harrison. EA Technology. 2003.

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Small recip. CHP: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	5.5 kWe* 12.5 kWth	This gives a heat to power ratio of 2.3:1 making the system suitable for applications with relatively low thermal demand compared with electrical demand.
Lifetime	10 yrs (2005) - 15 yrs (2015)	With technology maturity, the lifetime is projected to increase to meet the current lifetime of 15 years for gas boilers.
Maintenance cost	10% (2005) reducing to 4% (2015)	Maintenance costs will reduce with maturity and experience. The 4% value is slightly lower than conventional condensing gas boilers#.
Load factor	30%	A 30% load factor produces 33 MWh thermal energy and 14 MWe p.a. – Heating is typically not required for more than 30% of the time in domestic installations**.

The following base costs are applicable to small recip. CHP generated energy:

- Hybridised base costs using domestic electricity and gas heating prices and electricity export sale price.

(*) These are based on specifications for commercially available small reciprocating engine CHP systems.

(#) These values are based on an increase in servicing experience and infrastructure combined with improved reliability. Reciprocating engine technology is mature allowing relatively low maintenance costs to be achieved. A value of 5.5% is given in the case study in "Micro-CHP Fact sheet: United Kingdom". COGEN Europe. 2005.

(**) 30% is the maximum in-use load factor in a domestic environment without introducing heat-dumping. Based on Element Energy CHP systems experience.

Large recip. CHP: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	33.3 kWe* 50 kWth	This gives a heat to power ratio of 1.5:1 making the system suitable for electricity-led commercial applications.
Lifetime	20 years	The high maturity and reliability of reciprocating engines in this size range ensures a relatively long lifetime of 20 years.
Maintenance cost	7%	Maintenance of recip-CHP systems is currently high#.
Load factor	57%	A 57% load factor represents 5000 hours p.a. operation in CHP mode. This allows for electricity-led operation in a commercial application**.

The following base costs are applicable to large recip. CHP generated energy:

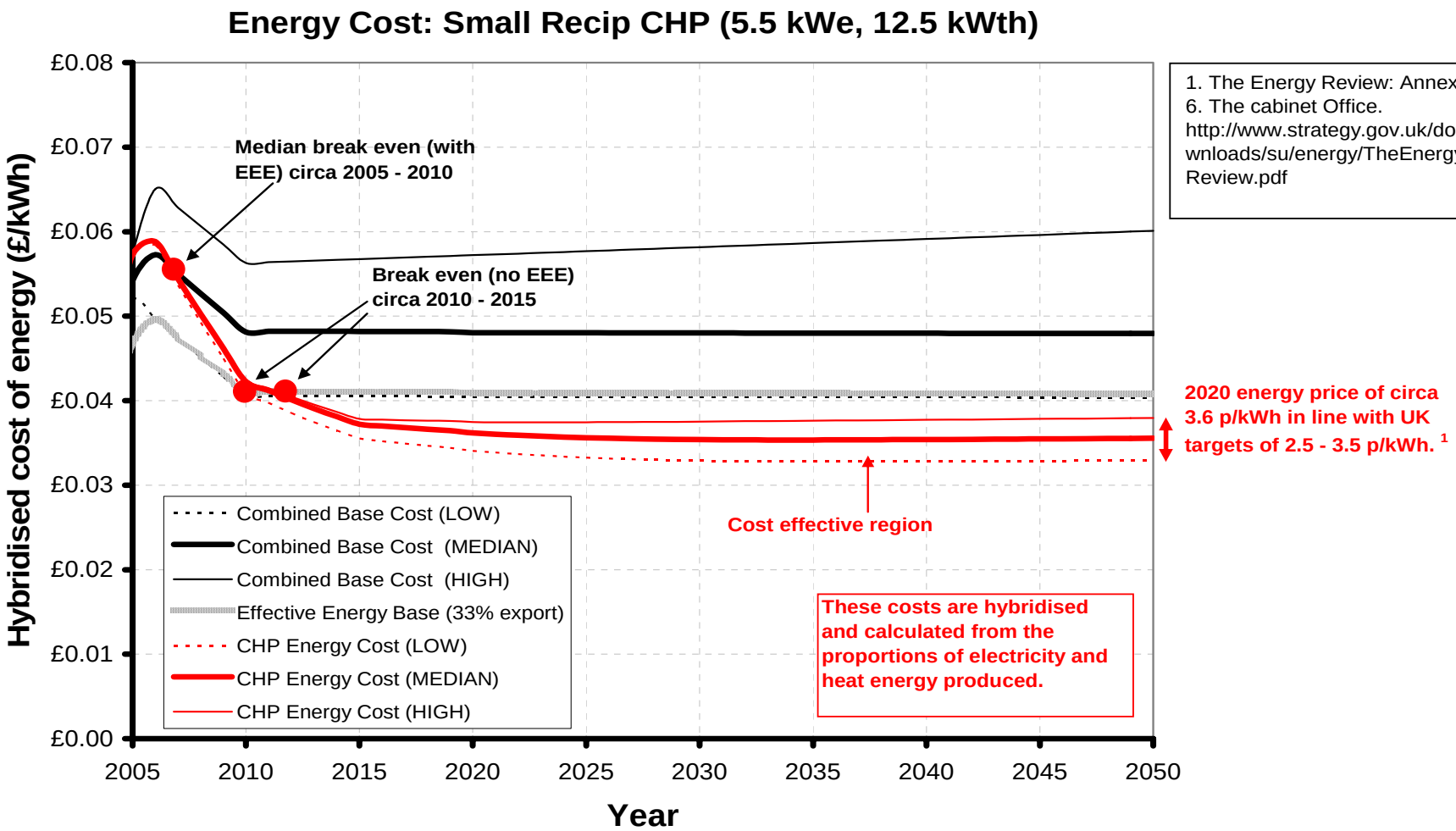
- Hybridised base costs using commercial electricity and gas heating prices. All electricity is used on-site.

(*) These are based on specifications for commercially available large reciprocating engine CHP systems.

(#) This value is based on a maintenance cost of 1 p / kWhe expressed as a percentage of the capital cost. Data taken from http://www.esru.strath.ac.uk/EandE/Web_sites/97-8/chp_sizing_case/econ.html and "Adoption and diffusion of de-centralised energy conversion technologies: the success of engine co-generation in Germany". Madlener R and Schmid C. Energy and Environment, Vol. 14, No. 5, 2003.

(**) 5000 hours operation per year is typically the maximum based on Element Energy CHP experience.

Small recip. CHP: generated energy costs. Median break-even predicted 2005 – 2010 (with EEE).



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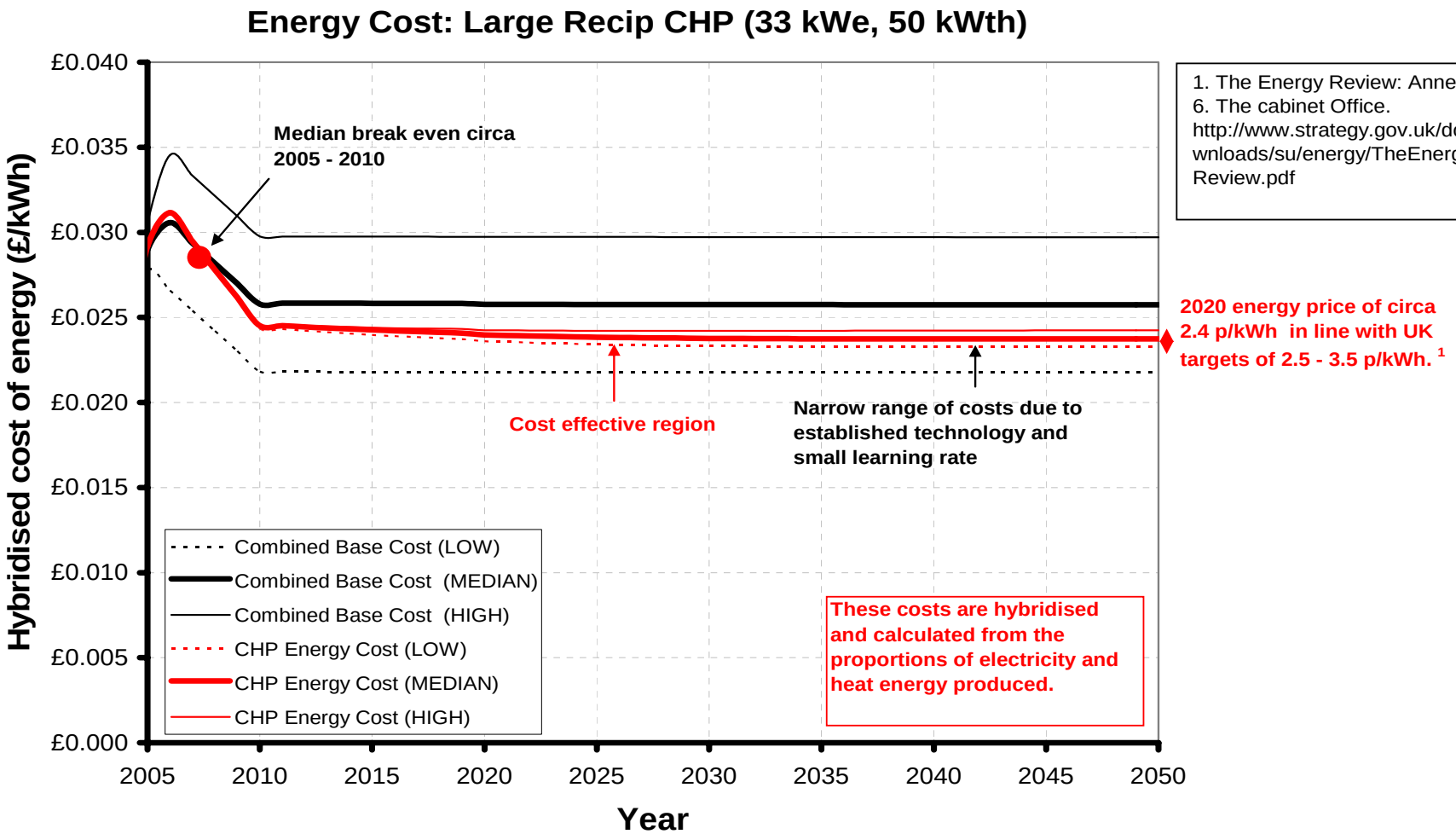
Large recip. CHP: generated energy costs. Median break-even predicted 2005 – 2010.



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Reciprocating engine CHP: generated energy costs. Comments.

- Break-even for small and large recip. engine CHP systems is predicted 2005 – 2010.
- The cost of energy for both systems in 2020 is in line with UK targets for CHP of 2.5 – 3.5 p/kWh.
- The final costs stabilise at 2.4 p/kWh (large recip.) and 3.5 p/kWh (small recip.).
- When electricity is exported at 33% for the small recip. system, the absence of energy export equivalence (EEE) could delay the break-even point by up to 5 years.

Solid Oxide Fuel Cell (SOFC) CHP: installed capital costs.

2005 Installed Capital Costs

Heat to power ratio 1:1 SOFC CHP: £5500 / kWe

- The fuel cell market is in its infancy with most systems at prototype level.
- A number of companies are developing SOFC CHP systems for the residential market with current pilot programmes in operation and product launches aimed in the next few years*.
- The price of £5500 / kW is based on our knowledge of the fuel cell industry and work with SOFC CHP developers#.

Two different generic systems are considered with different residential operating regimes:

1. **1 kWe, 1 kWth** SOFC CHP. This system is modelled with a 50% capacity factor due to electricity-led operation**. Thermal output provides some water and space heating. Electricity export is 33%.
2. **3 kWe, 3 kWth** SOFC CHP. This system is modelled with a 40% capacity factor for heat-led operation (providing 10,512 kWth p.a). The 1:1 heat:power ratio produces 10,512 kWhe p.a of which 72% is exported (the extra electricity produced over the 1 kW system is all exported)##. They could have the potential to replace large, centralised generation capacity, with significant decentralised generation.

(*) Fuel Cell Market Survey: Small Stationary Applications. Fuel Cell Today. 2004. http://www.fuelcelltoday.com

(#) Element Energy Ltd has studied the global market of stationary fuel cell technologies in previous studies and has consulted with a number of SOFC CHP developers.

(**) This system provides 4380 kWe and 4380 kWth per annum to provide typical residential electricity demand and some water and space heating (additional heating is supplied in heat-only mode, not modelled here).

(##) The 72% is obtained from 33% export of 4380 kWe (from 1 kW system) with an additional 6132 kWe (excess from 3 kW system) out of a total generated of 10,512 kWe.

SOFC CHP: scenarios for projected installed costs to 2050.

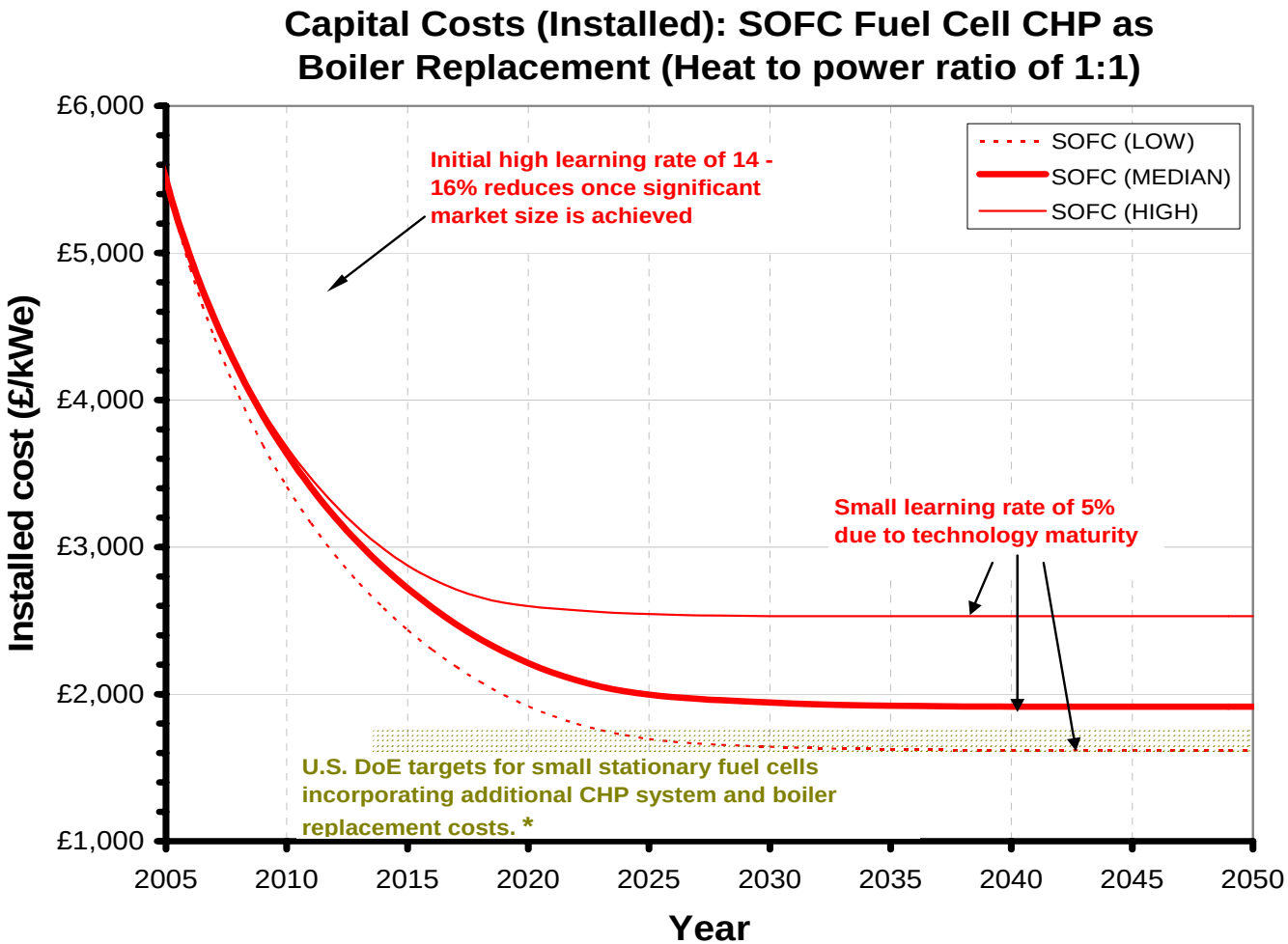
- The learning rate for SOFC is relatively strong due to immature technology.
- The general long-term market growth of fuel cells is high. A value of around 40% is based on market research*.
- Three scenarios are created by changing the learning rate and growth change.

Cost scenario	Rate of change in annual growth per annum (% p.a.)	Learning rate (%)	2050 Cost (£/kWe)
Low	-2% change per annum *(from initial growth rate of 40% p.a.*)*	16% reducing to 5% *(represents a greater potential for cost production)*	£1618 / kW
Median	-2% change per annum *(from initial growth rate of 40% p.a.)*	14% reducing to 5%	£1914 / kW
High	-3% change per annum *(the annual growth reduces more quickly)*	14% reducing to 5%	£2530 / kW

(*) Data taken from industry surveys. Fuel Cell Today. http://www.fuelcelltoday.com

SOFC CHP: projected installed costs for systems to 2050.

- The cost of a SOFC CHP unit as a boiler replacement is projected to reduce to circa £2000 /kWe by 2050 in line with U.S. targets*.
- This is in line with shorter term industry projections of £2500 /kWe#.
- 2050 projections represent an on-cost of around £700 /kWe above the replaced boiler cost – this is the extra paid for the CHP capability.



(*) Hydrogen, fuel cells and infrastructure technologies program: Multi-year research, development and demonstration plan. EERE, U.S. DoE. 2003

(#) Based on discussions with a SOFC CHP developer in 2005.

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SOFC CHP: technology specific inputs for modelling projected generated energy costs to 2050.

Inputs to cost-of-energy model

Parameter	Value	Notes
Rated power	**1 kWe, 1 kWth** **3 kWe, 3 kWth**	**Sized for electricity led operation (33% export)** **Sized for heat led operation (72% export)**
Lifetime	**1 kWe: 5 yrs (2005) - 15 yrs (2015)** **3 kWe:5 yrs (2005) - 15 yrs (2015)**	**Technological improvements aim to increase the lifetime of SOFCs*.**
Maintenance cost	**1 kWe: 13% (2005) – 8% (2015)** **3 kWe: 10% (2005) – 4% (2015)**	**Maintenance costs will reduce with maturity and experience#.**
Load factor	**1 kWe: 50%** **3 kWe: 40%**	**Electricity-led operation.** **Heat-led operation.**

The following base costs are applicable to small recip. CHP generated energy:

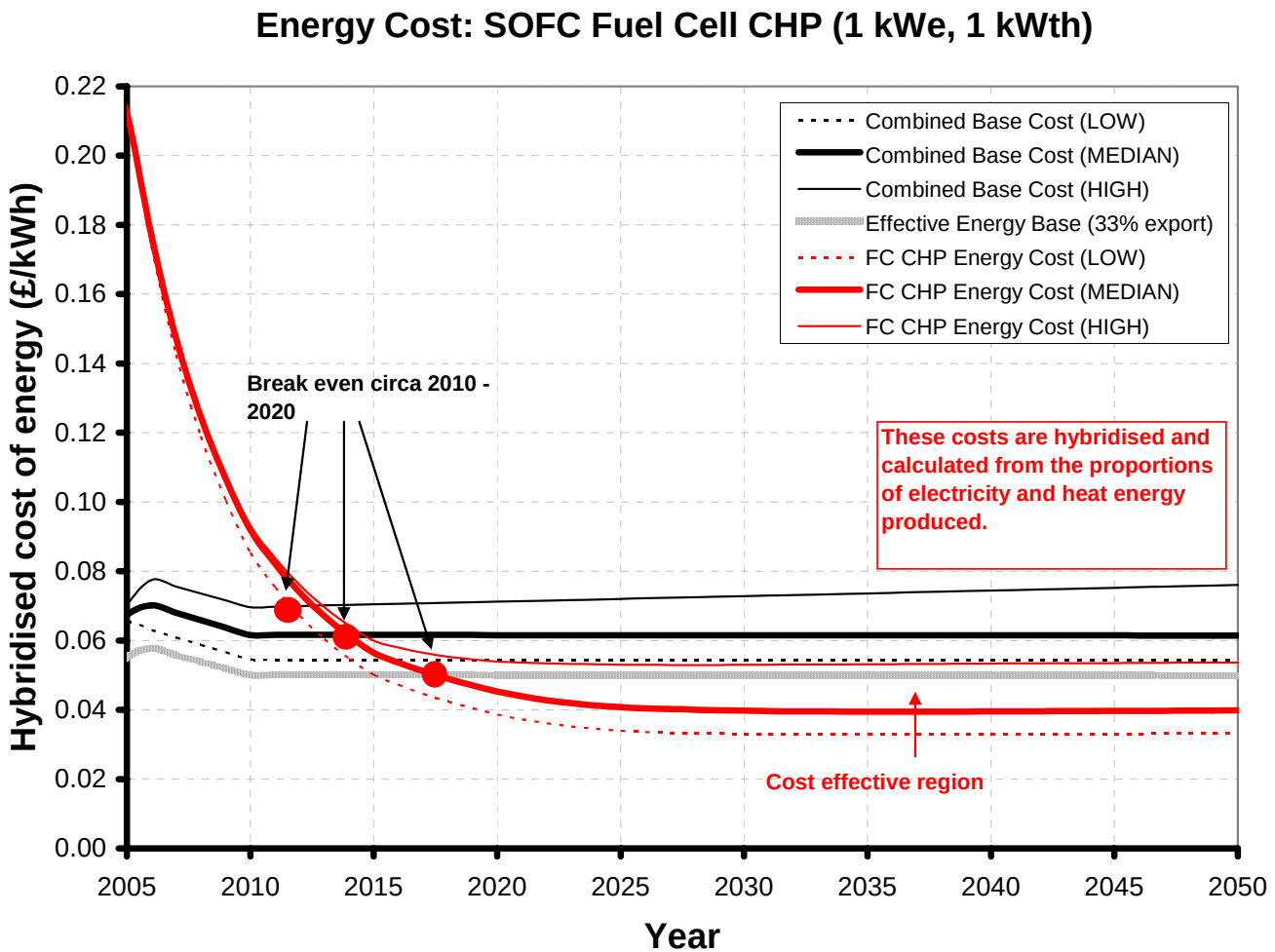
- Hybridised base costs using domestic electricity and gas heating prices and electricity export sale price.

(*) Based on current lifetime and the requirement for boiler-equivalent lifetimes in the future. A US target is 40,000 hours by 2010, corresponding to about 10 years at 40 – 50% load factor (from Hydrogen, fuel cells and infrastructure technologies program: Multi-year research, development and demonstration plan. EERE, U.S. DoE. 2003)

(#) These values are estimates based on industry consultation, with increases in servicing experience and infrastructure combined with improved reliability. The simplicity of SOFC technology could enable maintenance costs to approach current boiler maintenance costs of 5%.

SOFC 1 kWe CHP: generated energy costs. Break-even predicted 2010 – 2015.

- Median break-even predicted (both with and without EEE) circa 2015.
- The 1 kW Fuel cell CHP has the potential to be the most cost-effective technology: 2050 costs are predicted to be 1 p/kWh (with no EEE) and 2 p/kWh (with EEE) below the base cost .
- The break-even points are close due to large capital cost reductions in the short term.



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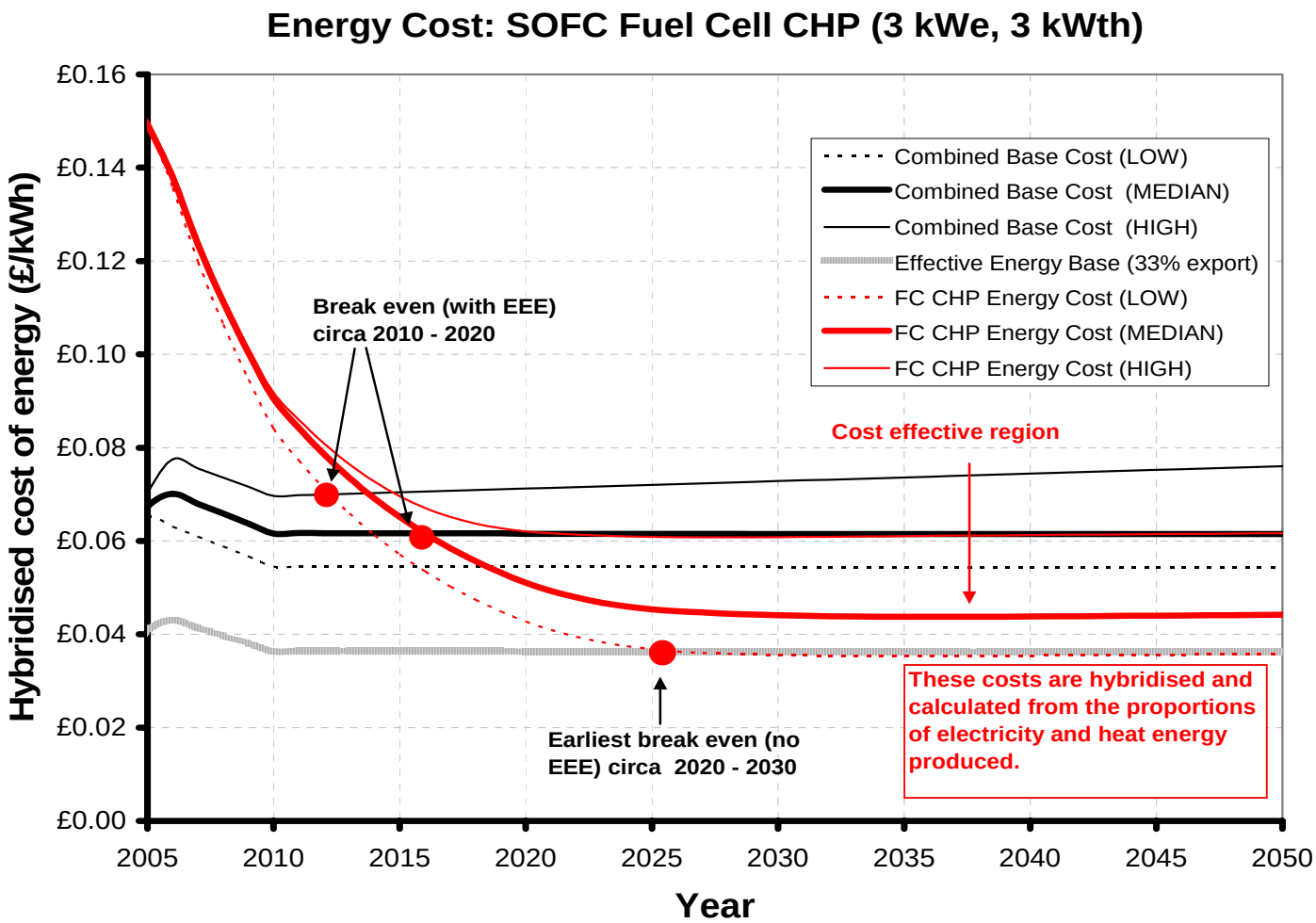
SOFC 3 kWe CHP: generated energy costs. High export percentage significantly delays break-even.

- Median break even for EEE scenarios predicted circa 2015, similar to 1 kW system.
- EEE is essential for economic operation: The median cost of generated energy is predicted to stabilise above the non-EEE base level (with 72% of electricity exported).
- De-centralised generation will only be economic if an EEE arrangement is introduced where micro-generators are paid a higher price for exported electricity.



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Contents

Summary – electricity generation.

PV

- The cost of energy is currently very high due to large capital costs. Incentives are required until circa 2030, and EEE metering will still be necessary after 2030, for PV to be economic.
- Domestic PV could be cost-effective with EEE circa 2030. Without EEE, cost-effectiveness can only be achieved with a cost/performance breakthrough.
- Cost effectiveness for commercial PV is not predicted before 2050 caused by low commercial electricity prices.

Wind

- Under the median scenario, domestic small wind could be cost effective by 2010 – 2015, but always requires EEE.
- Cost-effectiveness for commercial small wind is delayed circa 5 years due to the low commercial electricity cost.

Hydro

- Smaller hydro systems (0.7 kW) can be cost-effective with EEE. Significant cost reductions are required for break-even without EEE.
- Cost-effectiveness with commercial baselines is predicted only if there are significant reductions in capital costs. This is predicted for 2015 – 2020 with EEE and circa 2050 without EEE.

Summary – heat generation.

Solar water heating

- Solar water heating does not break-even with gas boiler water heating, and will require large cost reductions to break-even with electrical water heating by 2015 – 2020.

Biomass heating

- Biomass heating can currently be economic compared with electrical heating, but large cost reductions are necessary for break-even with gas heating.

Ground source heat pumps

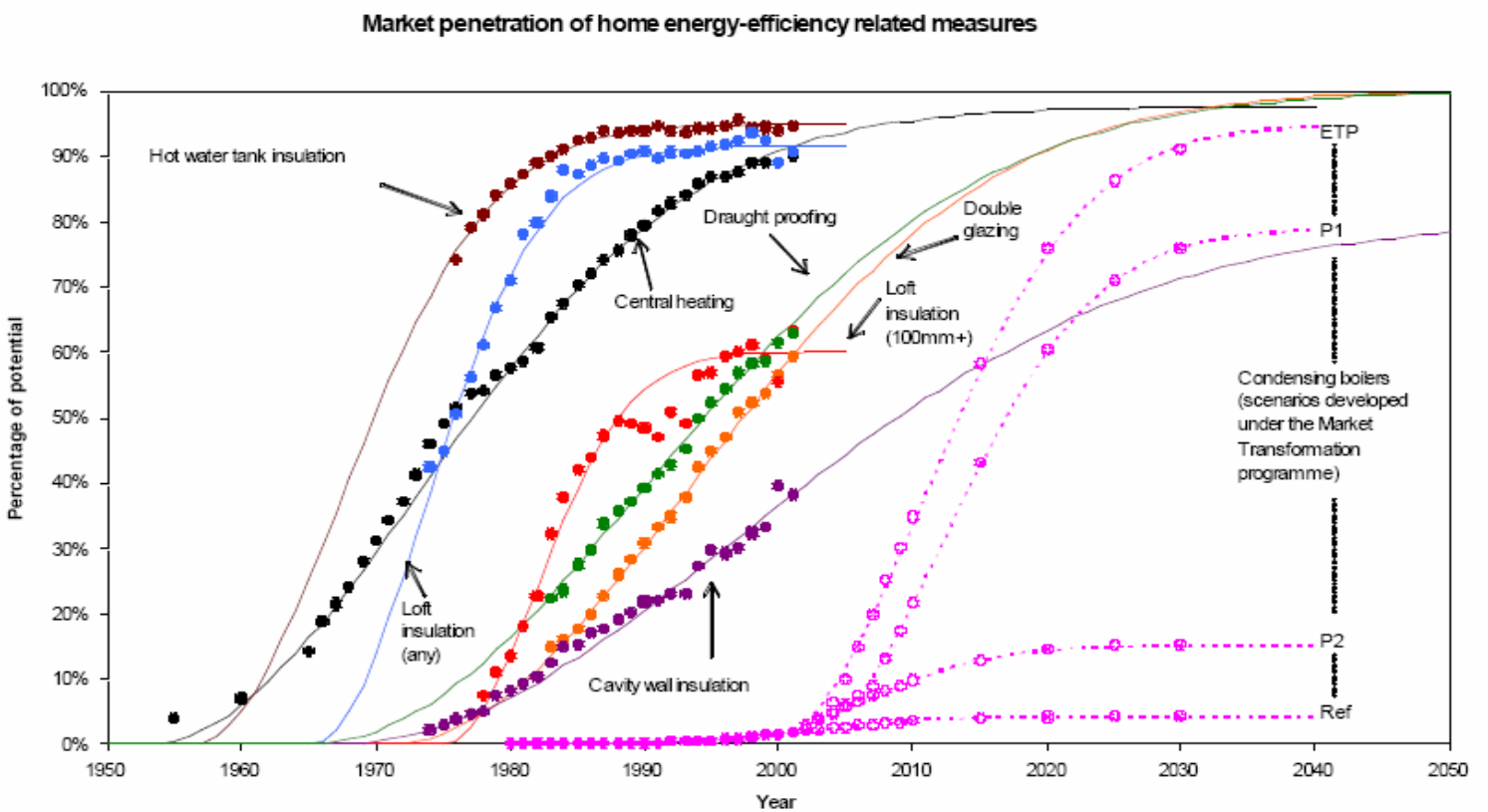
- GSHP shows potential for break-even with electrical heating circa 2005 – 2010, but is not projected to be cost-effective with gas heating.

CHP

- EEE metering enables the break-even of Stirling and small reciprocating engine CHP systems circa 2005 – 2010. The absence of EEE delays this by approximately 5 years.
- Fuel cell CHP is potentially the most cost-effective technology with break even circa 2015 and generated energy costs up to 2 p/kWh below baseline costs by 2050.
- The small 1 kW electricity-led fuel cell CHP achieves cost-effectiveness both with and without EEE circa 2015.
- De-centralised generation by the larger 3 kW heat-led fuel cell CHP requires EEE for cost-effectiveness, due to the large fraction of electricity exported. Without EEE, break-even is not predicted in the median cost scenario.

Contents

Technology uptake modelling.



- A vast amount of historical evidence points to the existence of "S-shaped" curves of technology adoption. The chart above* shows how various domestic energy efficiency and heating measures have been taken up in the UK. Certain measures can saturate the market within 20 years of introduction: others can take much longer (70 years for cavity wall insulation)

(*) Domestic Energy Factfile (BRE, 2000).

Technology uptake modelling.

Microgeneration technologies represent a new challenge for modelling of energy markets. To realise their potential, they must be installed in their millions by individual households. They will be affected by the behaviour of individual consumers in a way in which large scale planned central energy systems are not.

A number of approaches have been developed to predict uptake of a new technology by consumers

- Infection/epidemic models (very well established).
- Game Theoretic Models (recent).
- Probit models.

1) Infection / Epidemic Model

- A user of the technology passes on information to others, who in turn adopts the technology and spreads the word.
- The “population” of users is assumed to be homogeneous – the only explanation for uptake rates is that it takes time to transfer information about the technology.
- This is a “global” model; the overall shape of the S-curve is defined by a small number of parameters which remain constant through time. To define these requires some data about the market to-date. It is more suited for technologies that have already reached a significant percentage of the population.

Technology uptake modelling.

2) Game Theoretic Models

- Early in the diffusion of a new technology, consumers are faced with more than one choice of product, or supplier. A very small percentage of consumers (innovators) will purchase the technology due to its innovative aspects – there is no strategy to their purchase.
- Most consumers choose to wait and see which product is likely to be successful, before they adopt themselves. This minimises the risk that they invest in the wrong technology.
- Once an accepted technology emerges, uptake grows quickly, as is seen in the S-curves.
- This approach is useful for explaining why technology diffusion is initially very slow, and also why most products fail.
- Its application to energy sector technologies is unclear, and the preferred approach is to use the next model type (probit models).

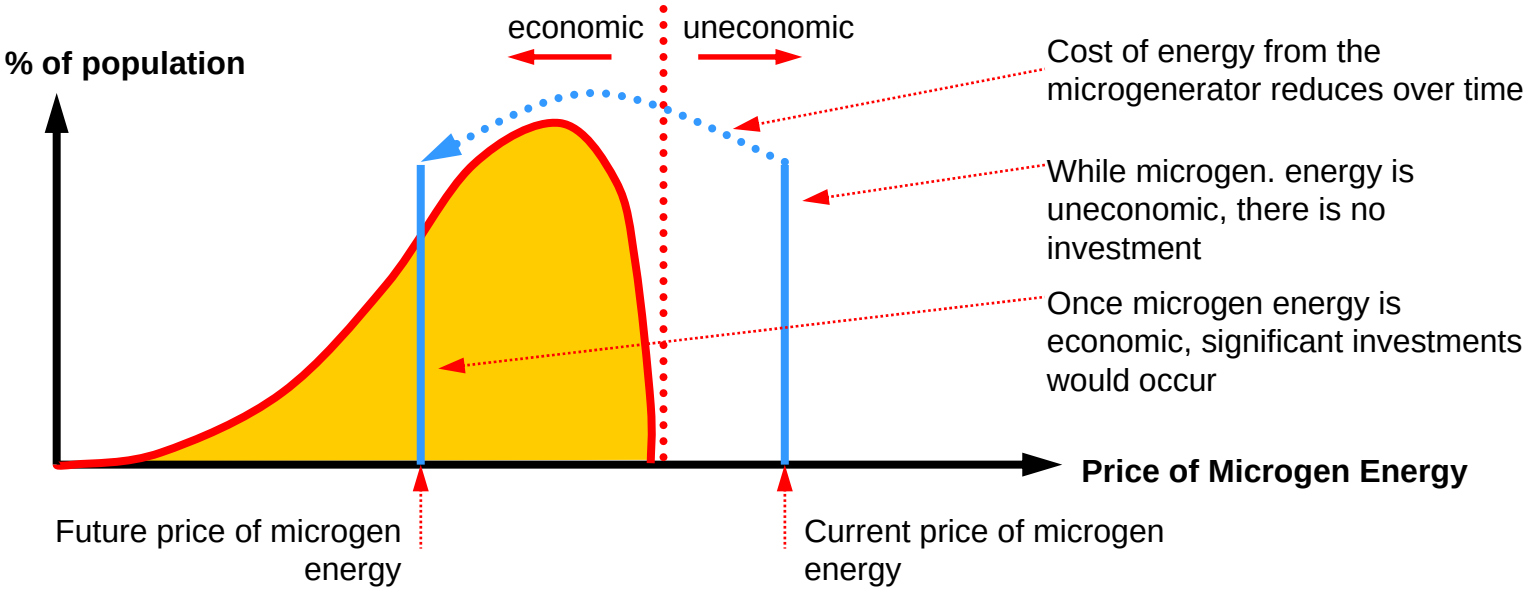
(*) This is analogous to the VHS V Betamax competition for home video. Early on, it was not clear which technology was going to be successful. Only once VHS looked like it would prevail, did early adopters purchase the technology. By removing the alternate technology, manufacturers were able to concentrate efforts, and reduce cost and hence boost uptake further.

Technology uptake modelling.

3) Probit Model

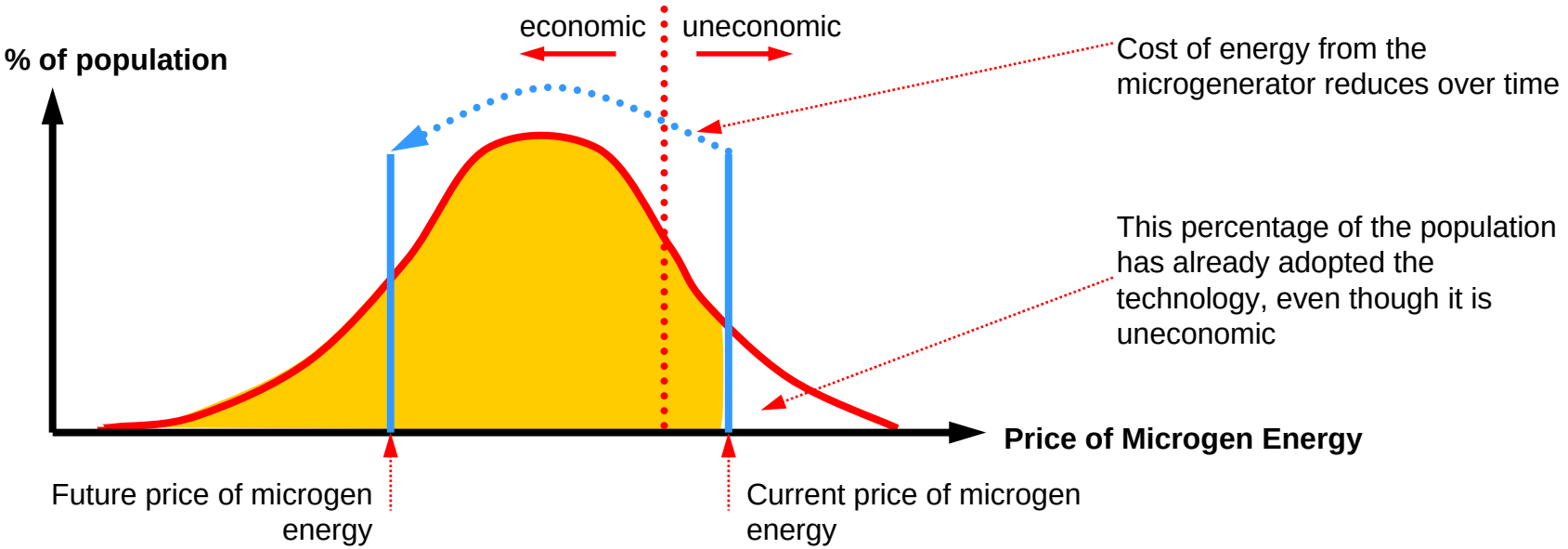
- This approach assumes that every adopter sets a test for the technology; in most cases, the test is whether the investment is cost effective. If the technology passes the test, a purchase is made.
- For a typical commercial adopter, an investment would only occur if the technology was cost effective.
- However the population as a whole is more flexible with regards to investment decisions, and the “willingness to pay” can vary through the population.
- Some of the population may be prepared to accept an on-cost , while others may want an investment to be highly profitable before a purchase is made.

Willingness to pay curves: “rational” decision making.



- In the above illustration, the cost of energy produced by the microgenerator, is reducing through time.
- In this case, no section of the “commercial” population is willing to invest uneconomically – decision making is largely rational.
- Most of the population is clustered around the economic threshold: they will adopt once the cost of energy reduces to economic levels. Some of the population remains sceptical, requiring a strong incentive (i.e. cheap energy) to invest.
- With this distribution of “willingness to pay”, the resulting uptake curve would take off sharply once cost-effectiveness is reached.

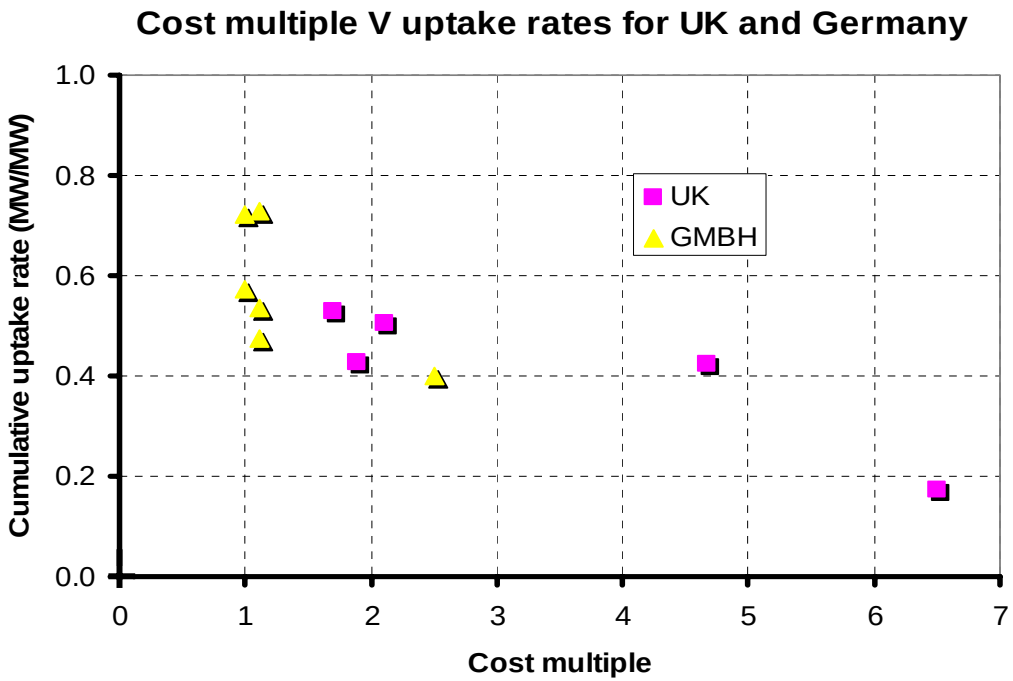
Willingness to pay curves: “irrational decision making”.



- In this example, a percentage of the population is willing to invest before the cost of microgen. energy is economic. The reason for the investment may be an enthusiasm for the technology, or a higher than average valuation of the environmental benefit of the technology.
- The above example (with a normal-type distribution of willingness to pay) results in a classic S-shaped uptake curve.
- Although the “irrational” decision makers may comprise a small percentage of the population, their role as innovators can be crucial in supporting a technology in its early phase, providing a bridge to commercialisation.

Defining willingness to pay.

- Some uptake models assume the population behaves rationally; that there is no investment when the cost of energy is above a commercial level*.
- Empirical data from the microgeneration market suggests otherwise. This graph shows growth rates in the UK and German PV markets, over recent years**. The graph clearly shows growth even when the technology is highly pre-commercial.
- The graph shows that uptake rates are higher when the cost of energy is economic. (In Germany, a feed-in tariff is structured to provide energy at a cost multiple close to 1).



Cost multiple is defined as:

$$\frac{\text{(cost of energy from microgeneration)}}{\text{(cost of energy from incumbent energy supply)}}$$

(*) The INVERT uptake model; Energy Economics Group, University of Vienna. (www.invert.at)

(**) Cost multiple is defined as the cost of microgen energy divided by the baseline (commercial) cost of energy. If Cost Multiple > 1, the technology is not cost effective.

Defining willingness to pay.

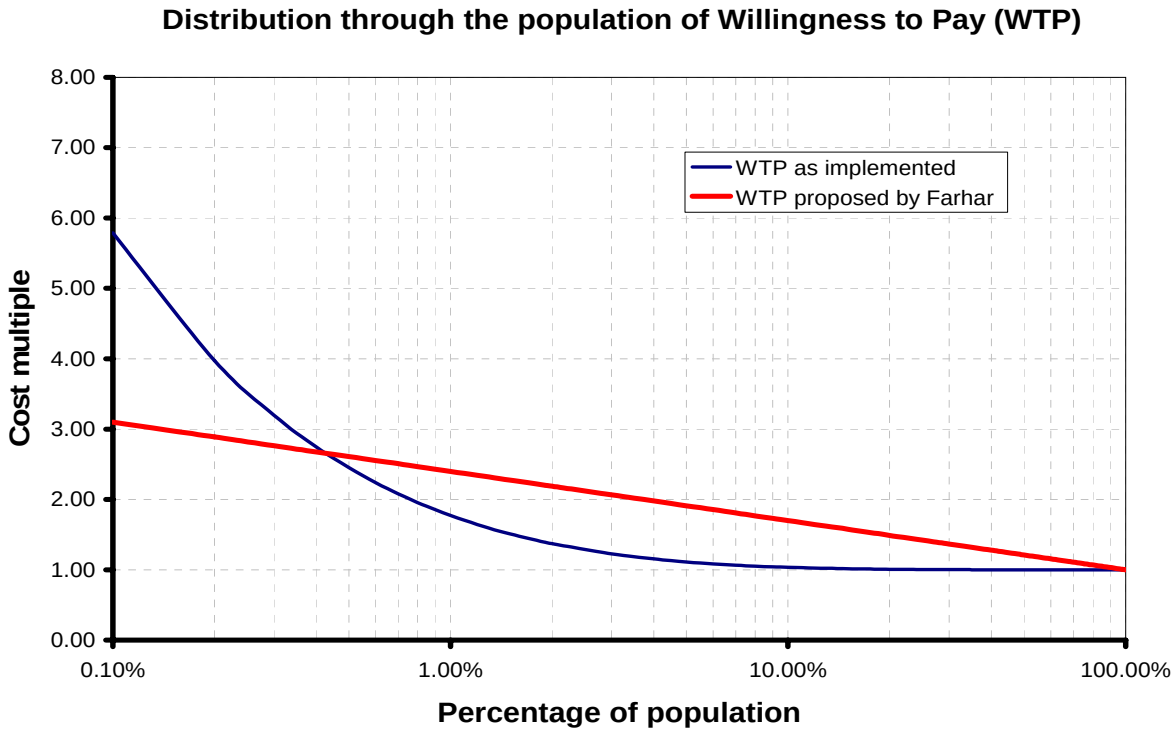
- The development of an uptake model, particularly one which could be dependent upon highly irrational decision making, is open to significant uncertainty. The distribution through the population of “willingness to pay” is vital in the prediction of uptake rates.
- There is very little data in the literature with regards to such models, however one paper is often cited for “willingness to pay” data.
- The Farhar* paper collated responses from national polls in the US regarding willingness to pay an on-cost on utility bills for “green” electricity.
- The paper concludes that most of the population is willing to pay an on-cost for green energy (between 30% and 90% of the population). This seems high, and is much higher than participation rates in utility-led green energy programmes (which is circa 1% of the population), suggesting a positive response bias skewed towards renewables**.
- The uptake model used by the US Department of Energy*** shows much more price/demand elasticity.
- Therefore, a more conservative WTP curve is proposed for the current model.

(*) Farhar, B.C; “Willingness to Pay for Electricity from Renewable Resources: A review of Utility Market research”; NREL July 1999

(**) Jensen et al, “An analysis of residential preferences for green power”, Uni. of Tennessee, 2004.

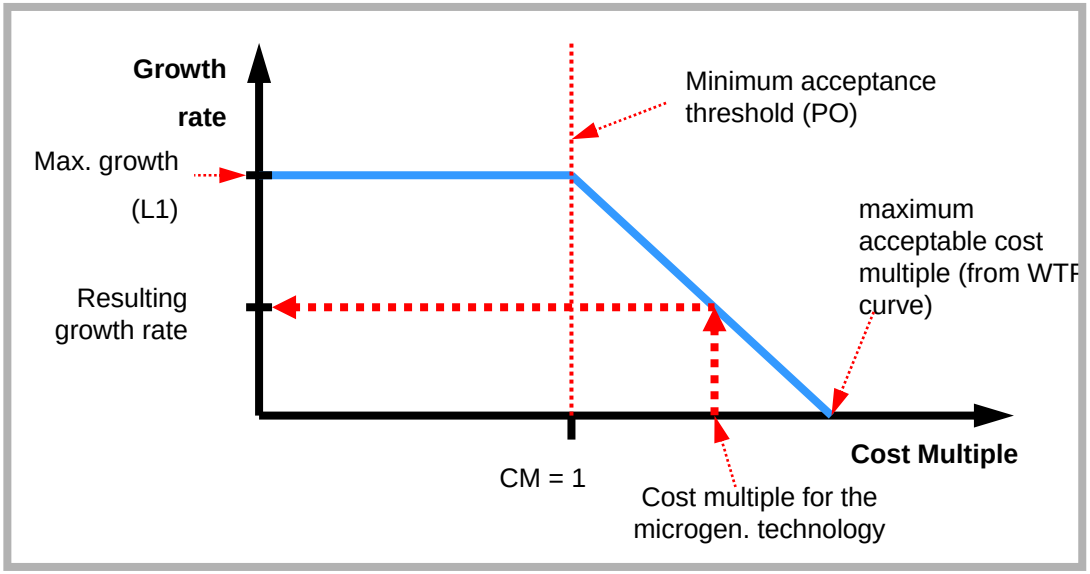
(***) Boedecker et al; “Modelling Distributed electricity generation in the NEMS building Modules“, US Doe 2000. This model suggests that highly commercial technologies (i.e. with payback periods of 1 to 20 years) are taken up relatively slowly (circa 20 years required for saturation).

Defining willingness to pay.



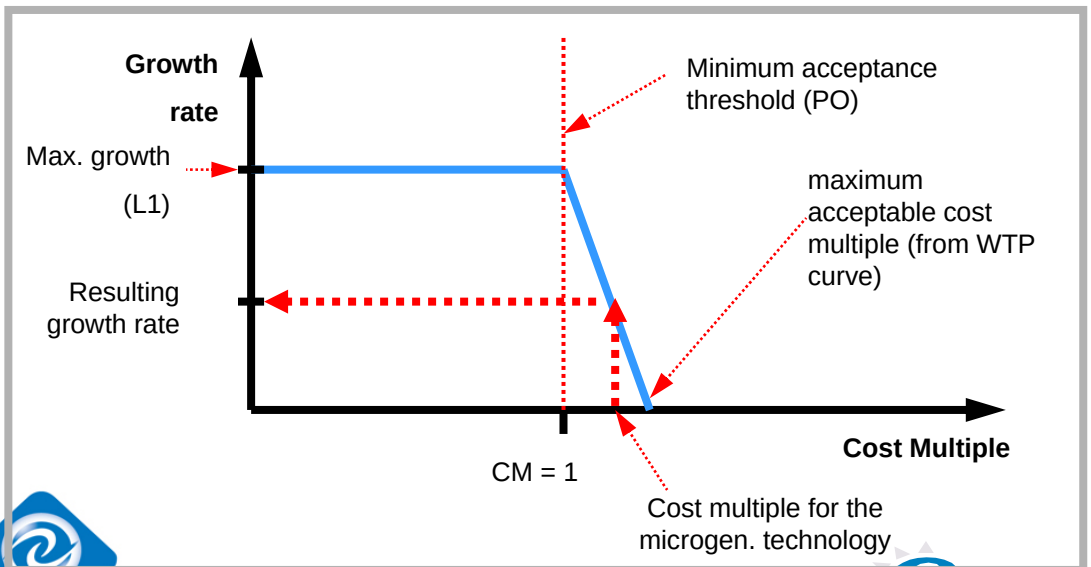
- The graph above shows the distribution of WTP through the population, as proposed by Farhar and as implemented in the current model.
- The implemented WTP curve corrected two failings of the Farhar data:
  - WTP for the most innovative section of the population (0.1%) was too low, preventing any uptake of certain high cost technologies (such as PV)
  - WTP for the majority of the population was too high; this now approaches unity for most of the population.

Technology uptake modelling.



At LOW uptake levels

- For a small percentage of the population (the innovators), the maximum acceptable cost (taken from the WTP curve) is high.
- Therefore, technologies with high cost multiples can be taken up (although uptake rates are higher if the technology is more cost effective).
- A maximum growth rate is imposed when the cost multiple is below one.



At HIGH uptake levels

- For most of the population, the maximum acceptable cost (taken from the WTP curve) is much closer to one.
- The cost of energy must reduce over time if growth is to continue.
- If cost does not reduce quickly enough, the market stagnates.

Technology uptake modelling.

Heterogeneity of acceptance levels in the current model

Varying maximum acceptable cost:

- This is Willingness to Pay, and varies through the population, from innovators (with a high WTP) to late adopters (with a much lower WTP).

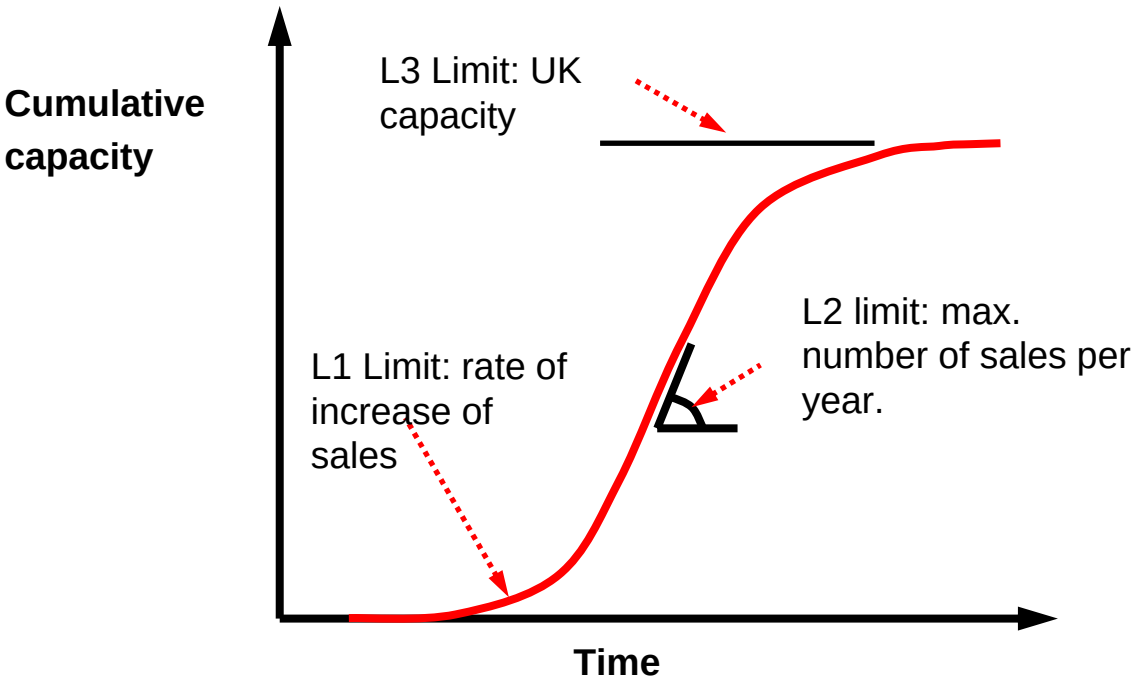
Varying L1: maximum growth rate

- Initially, the maximum growth rate that can be achieved – even if the technology is made very cost effective, is 70%.
- Observation is that most technologies find it difficult to sustain > 30% when significant capacity is reached.
- Therefore, as capacity increases (to levels equivalent to mass uptake), L1 tends towards 30%.

Varying PO: minimum acceptance threshold

- The acceptance threshold is typically set at one. However, varying this value can have a substantial effect on uptake levels.
- More sceptical consumers would have a lower P0 (eg. 0.8). This means that the cost of energy must be significantly lower than the baseline before the customer is prepared to invest.

Technology uptake modelling.



Three limits to uptake are imposed on the model

- L1 – maximum rate of growth of the market per year.
- L2 – Maximum number of sales per year
- L3 – UK technical capacity to accept technology

Contents

Appendix A2.2 – base assumptions for the uptake model

Assumptions sheet

Scenario name	PV: 2.5kWe (Dom.)	PV: 40kWe (Comm.)	Wind: 1.5kWe (Dom.)	Micro-hydro: 10kWe (Dom.)	GSHP V Elec. Heating (Dom.)	Biomass V Elec. Heating (Dom.)	Active Solar V. Elec Heating (Dom.)	CHP 1.2kWe Stirling - Large House	Fuel Cell - 1kWe (small house)	CHP 33kWe Large Recip.	FC: 3kW (large house)
Maximum yearly sales - L2 (in MW)	1000	360	600	15	325	347	275	900	750	20	1800
Maximum installed capacity - L3 (in MW)	25000	9000	19000	100	5000	5200	5500	9236	8700	566	18480
Lifetime	25	25	20	20	20	20	15	15	15	20	15
Assumed equipment size (kW output)	2.5	40	1.5	10	5	20	2.8	1.2	1	33	3
Heat to power ratio (if any)	0	0	0	0	0	0	0	7	1	2	1
Cost 2005	5000	4000	3000	2700	900	250	1600	679	4200	756	4200
Cost 2020	1383	1107	843	2280	701	225	1112	472	975	680	975
Cost 2050	742	593	716	1787	635	198	1015	446	733	663	733
Maintenance cost (fraction of capital)	0.01	0.01	0.018	0.03	0.05	0.03	0.02	9%	8%	7%	4%
Installed in 2005 (MW)	2	10	0.2	1	1	5	143	0.07	0.025	7	0.025

Nb Technology and maintenance for domestic CHP based on the on-cost above a domestic boiler

These values are referenced in Appendix 1 for the applicable technologies.