The Adoption of a Decentralized Energy Technology: The Case of UK Engine Cogeneration

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ABSTRACT

Adoption of decentralized energy technologies will be crucial in the evolving structure of energy markets and the magnitude of future greenhouse gas emissions. This detailed analysis of the adoption of engine cogeneration gives insights into organizational decision making regarding the diffusion of a cost effective decentralized energy technology. Detailed site information on over 600 UK cogeneration installations was collected and analyzed for the six year period during which UK energy markets were in the process of deregulation. A detailed examination using standard investment criteria of the cogeneration schemes indicated that over 70% of investments were of questionable economic value to adopters. This was because these installations were below our calculated minimum economic size threshold. A key determinant of this size threshold was found to be the fixed costs of maintenance. Analysis of the financing of installations revealed that the largest fraction of poor investments occurred in energy services agreements between suppliers and adopters. The policy implications for decentralized energy technologies of a minimum size threshold and poor investment decisions by early adopters are discussed. Further research aims to explore postulated explanations for the observed decline in early adoption of UK engine cogeneration.

1. Introduction

This paper analyzes the adoption of engine cogeneration in the United Kingdom from 1992 through 1997. This decentralized energy technology meets industrial and building electricity and heat requirements, is cost effective and has been heavily promoted by the UK Government for economic and environmental reasons. Adoption of this technology is a discretionary investment. The deregulation of the energy market during the period of study resulted in falling conventional energy prices.

Investment decisions with respect to engine cogeneration are modeled using conventional NPV calculations under the assumption of a profit maximizing adopter. The key factors determining the decision making process and resultant investments in this technology are explored.

The motivations for studying this topic are:

- Study of the adoption of a cost effective decentralized energy technology in a competitive market.
- Insight into the slow uptake of energy efficiency measures, or the energy efficiency 'gap'.
- Further understanding of organizational decision making for a discretionary investment under unfamiliar market conditions.

2. Engine Cogeneration

Engine cogeneration from a auto-derived spark ignition engine uses proven technology, packaged and sold as a single unit. The engine is configured to run on natural gas and remotely monitored and controlled for efficient maintenance to ensure that the unit operates as desired. Electrical output ranges from 25kWe to 1,000kWe and is used to meet electrical and heat requirements in industry and buildings with heat output at 80-110°C. The heat to power ratio (HPR) ranges from 1.5 to 2, with the usual sizing methodology for base-heat load. Electricity generation occurs synchronously with the grid to facilitate back-up and top-up electricity supplies.

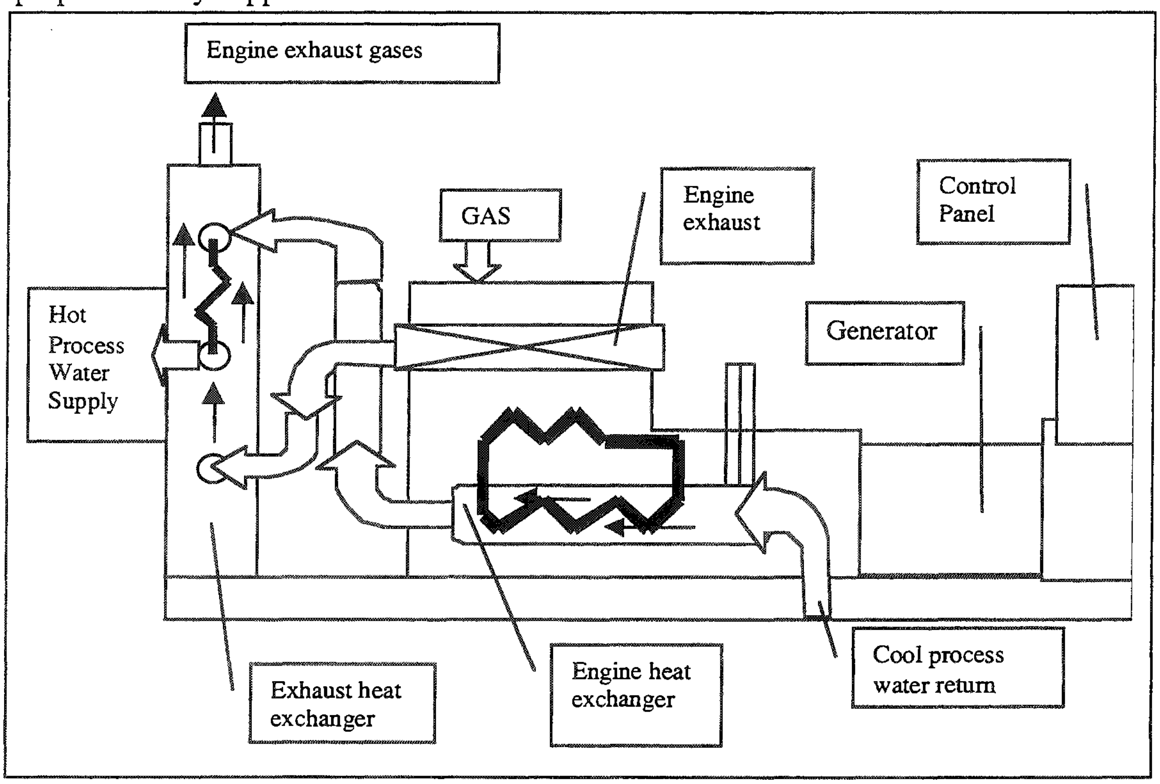

Figure 1: Schematic of engine cogeneration unit

As of 1997 there were over 1,000 installations in the UK with typical applications including industrial sites, leisure centers, hospitals, hotels, multi-residential housing, educational buildings and public establishments. Other applications had a limited penetration due to the necessity of having a continuous electricity and heat base-load for at least 4,500 hours per year (offices, retail). Installations serve single sites due to the practical difficulties and poor economic returns from the sale of electricity and heat. This study was partially motivated by UK Government research[1] estimates that the technology has only penetrated to 8% of its potential capacity. We knew that technical developments including new prime movers (for example, fuel cells or micro gas turbines), and the coupling of cogeneration to an absorption chiller to provide cooling in the summer months were not significant in the period studied. Therefore, we examined the actual performance of the technology, economics of investments and expectations about its adoption.

Economic savings are the rationale for investing in engine cogeneration, and are obtained from the high efficiency (typically 80%) of input energy to useful output and because gas is cheaper to buy than electricity. Therefore, the difference in electricity and gas prices governs return on investment. In addition, self generation can offset high time of day electricity charges in winter months and avoid the additional costs of a boiler. Costs are the capital investment in the unit, maintenance costs and the costs of making the decision. Environmental savings (emissions of CO_2 and SO_2) are not the motivator for investment but do give ancillary benefits to the adopter (and society as a whole). Other motivations such as power reliability have been suggested as decision variables, but discussions in a series of interviews with experts in the UK cogeneration industry suggested economic savings are the overwhelming rationale for investment.

3. Literature Review

The literature on energy efficiency investment shows energy efficiency measures have an historic rate of poor levels of adoption despite the high projected rates of returns, i.e. the "Energy efficiency gap" [Jaffe and Stavins, 1993]. Explanations include that in times of lower prices energy efficiency measures are implemented less [Newell, 1998], the additional costs that it poses to organizations to change their method of operation [Cebon, 1992], idealized engineering-economic projected savings are never achieved [Metcalf, 1998], and that decision makers are not aware of the technology [Morgenstern, 1996].

Theory on bounded rationality and satisficing says that decision makers settle not for the optimal solution for a problem but on the first solution that suffices a given criteria [Simon, 1982]. Diffusion theory models adoption using the logistic or S-shaped curve [Griliches, 1957] take the ceiling of adoption as those who did adopt, and not necessarily those who could adopt. Thus this analysis which seeks to understand why only 8% of the potential market had been penetrated was not based on the diffusion model. The techniques of investment under uncertainty (Dixit and Pindyck,1994] were not used due to the 'now or never' nature of an investment with an expected falling return.

4. Data Sources

The analysis is based on a unique cogeneration industry database[2] that provides detailed site, technical, sector, geographical and financing information on all 612 installations in the UK in the 6 year period from 1992 through 1997. This data is supplemented by a public database[3] that contains comprehensive site, sector and technical details of approximately 75% of installations from 1983 through 1991. In addition, data on energy

[1] ETSU, (1997).
[2] CHPA, Small Scale CHP Sales Database (1998), UK Combined Heat and Power Association, London.
[3] OFFER, CHP Database (1998), Office of Electricity Regulation, Birmingham, UK.

prices, energy intensities and estimates of cogeneration potential were utilized [UK DTI, 1998; ETSU, 1997].

Additional data sources were employed to ensure that the model calculating the return on investment was rigorous with all relevant factors considered. Firstly a series of detailed case studies[4] provided information on costs, the process of the investment decision, company strategies and operating experience of the unit. Secondly, eight open-ended interviews were conducted with a range of experts from differing viewpoints on engine cogeneration (adopters, suppliers, consultants, government experts, trade-body professionals).

5. Investment Conditions

An overview of the market conditions in which adoption of engine cogeneration was occurring, centers around the move to competition in the energy sector. The UK gas industry was privatized in 1986 and the electricity market in 1989. Progressive deregulation of the gas market led to the commercial and small industrial markets being opened to competition in late 1992 although it was not until 1994 that substantial competition in this sector was seen following the report on gas competition by the UK Monopolies and Mergers Commission. Similar moves toward competition in the electricity markets led to the commercial and small industrial sectors (100kWe to 1MWe) being deregulated in April 1994.

The increase in potential suppliers following the deregulation of the 100kWe to 1MWe electricity franchise market (in which engine cogeneration predominately operates), resulted in electricity tariff reductions of typically 13% (from 7.3c/kWh to 6.3c/kWh). Gas prices saw a similar decrease. This price reduction lowered incentives for all energy efficiency measures.

As well as price reductions, the set up of the competitive electricity industry effectively prevented electricity sales for small embedded generators located in the local electricity distribution system, for the relatively small amounts of electricity to be sold. This was because sales to customers with maximum demands of less than 100kWe (i.e. all residential customers), was still part of the franchise market of the incumbent utilities (until at least April 1998) and thus off limits to cogeneration adopters. The sale of electricity was restricted to the local utility, which typically offered tariffs of 4c/kWh as opposed to residential tariffs of 11c/kWh. The option of selling electricity to a neighboring facility of more than 100kWe still incurred significant use of distribution system charges paid to the utilities. The option of private wire construction entailed high costs and planning delays. Therefore, engine cogeneration has been limited to single site applications and sized to base heat load.

The investment in engine cogeneration is discretionary, with typical energy costs accounting for 5-10% of site operating expenditure. The decision process usually entails an energy or technical manager putting a proposal to a financial decision maker. Decisions are made on economic grounds, with environmental considerations being secondary. With the downgrading of the incentives for energy management, cogeneration suppliers responded by offering zero capital investment options, where the unit is owned by the supplier and the adopter pays for the cost of gas and receives both the unit's electricity at a reduced tariff and the heat output. The supplier's income comes from the electricity tariff and a maintenance

[4] Taken from the UK Department of the Environment, Transport and the Region's Energy Efficiency Best Practice Program.

contract for servicing and emergency callout (costing typically $20,000). This option allows the adopter to have no capital outlay (but still with a commitment to a long term contract [10 years]). The unit is the supplier's core business, thus overcoming the discretionary investment barrier and signaling a move towards an energy services concept when providing electricity and heat.

Engine cogeneration was heavily promoted for environmental savings by the UK Government as part of the 5,000MWe target by the year 2000 for all cogeneration investment, principally through the Energy Efficiency Best Practice Program. Cogeneration as a whole was earmarked for 13% of planned CO_2 emission reductions by the UK through the year 2000. European wide directives on power generation including SO_2 and NO_X control (for example, the Large Combustion Plant Directive) were not applied to engine cogeneration due to its small size.

6. Adoption Trends

Figure 2 graphs the number of units installed every 6 months and stratified by size (electrical). The smallest schemes (<50kWe) are no longer being offered and the other small schemes (<150kWe) have seen a large reduction in adoption rates. The demise of smaller sized schemes is discussed in the analysis of sizing and maintenance of the installations in Sections 9 and 10.

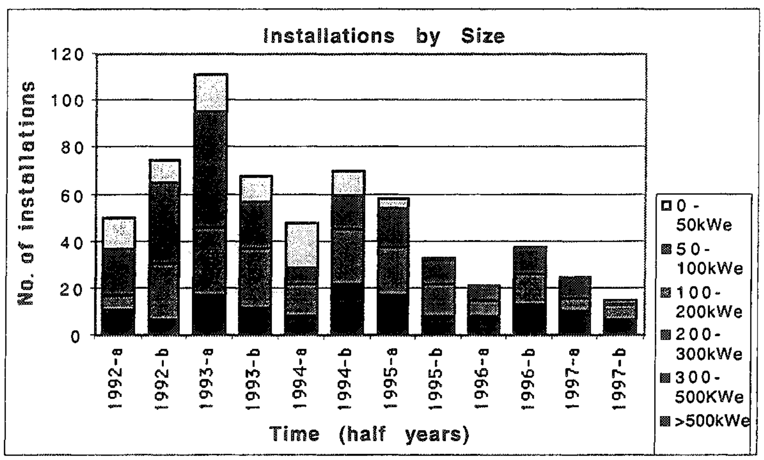

Figure 2: Engine cogeneration installations stratified by size

Figure 3 graphs the number of cogeneration installations by the type of investment. An optional investment is when the unit is retrofitted to an existing site to take advantage of its cost savings. A compulsory investment is when a decision must be made to invest in energy capital and some capital investment is required, including new build situations and extensions or refurbishment to a site. Compulsory investments remain relatively constant, while the optional investments show a substantial decrease. Compulsory investments give a slightly better rate of return due to some avoided costs, and a decision on investment in energy capital must be made. The demise of optional investments in engine cogeneration is discussed in relation to the financing of installations in Section 11.

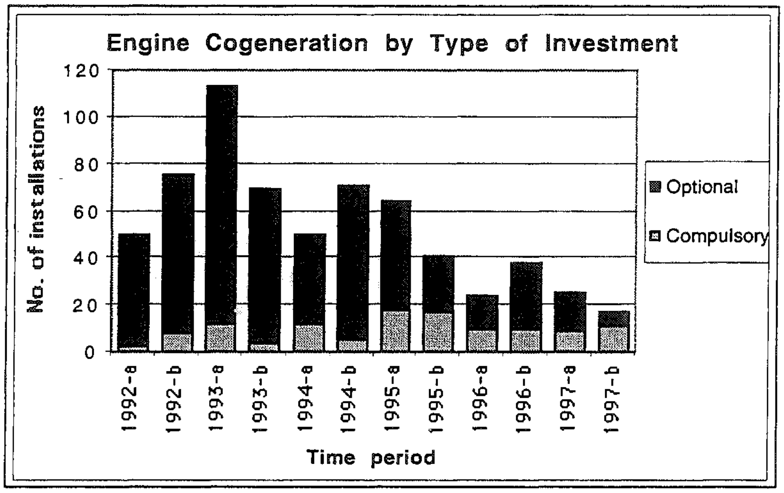

Figure 3: Engine cogeneration installations stratified by type of investment

7. Modeling and Analysis Framework

Parameter	Units	Model Value (discrete or probability distribution)
Size (electrical)	kWe	250
Discount rate	%	15
Capital cost	$	50000 + (Uniform (600,800)* Size)
Maintenance cost	c/kWh	Normal (1.6/0.1)
Winter hours planned	hrs	4380 – Triangular (0,1000,2000)
Winter downtime	hrs	Triangular (20,70,120)
Heat to Power Ratio (HPR)	number	Normal (1.7,0.13)
Summer hours planned	hrs	4380 – Triangular (0,1000,2000)
Summer downtime	hrs	Triangular (20,70,120)
Avoided boiler costs (compulsory case only)	$	Triangular (10000,15000,22000)
Electricity price	c/kWe	Actual prices every 2 months
Gas price	c/kWe	Actual prices every 2 months
Utility connection fees	$	Triangular (0,5000,20000)
Building services connection costs (optional case only)	$	Uniform (500,20000)
Consultant fee	$	Normal (3000,300)
Decision making costs	$	Normal(1000,200)
Winter peak electricity price	c/kWe	Electricity price / (1-Triangular(0,0.05,0.6))
Operating life of investment	years	15

Table 1: Base-case parameter values

A mathematical model to calculate return on investment (Net Present Value and Simple Payback Period) was constructed in the Analytica modeling environment. Each component is modeled by a mathematical expression and the output generated from Median Latin Hypercube sampling over 2,000 runs of the model. Input parameters are taken from the datasets cited, and additionally from the detailed case studies and expert interviews. The model is consistent with other investment return calculation models used for UK engine cogeneration [EEBPP, 1997]. The model considers the input costs, the site specifications, and the utilization and operation of the unit, and calculates the return of investment parameterized for bi-month periods over the 6 years of study using the actual energy prices for this sector, and by whether the investment was compulsory or optional.

The model's purpose is to calculate the return on investment in cogeneration and the key factors affecting this return. Systematic sensitivity and uncertainty analysis was carried out to ascertain these key factors in the investment calculation and they are further investigated in individual parametric analysis. A base-case installation is used when analyzing each of the key factors. All results given are, unless stated, calculated using the base case, outlined in Table 1.

8. Model Results and Key Parameters

The return on a cogeneration unit did not exhibit the same downward trend as conventional energy costs, because cogeneration return depends on the difference between electricity and gas prices, both of which were declining. Therefore the decline in adoption rates is not due to a poorer rate of return on the cogeneration investment.

An important reason in the decline in cogeneration adoption is the decrease in the cost of conventionally supplied electricity and heat, due to the deregulation of the electricity market and continuing decline in the cost of gas. A saving of 9.2% in conventional energy costs was attainable simply by signing a new energy contract. This is comparable to the savings obtained from the cogeneration unit. Therefore, although the savings from the cogeneration unit decreased only slightly, post deregulation savings from this investment were an additional cost reduction measure in an area where the organization had already made comparable savings. This explanation is supported by the regression showing a correlation of rising savings on prior energy bills due to deregulation and a reduction in the number of cogeneration installations. (R^2 =0.55, coefficient = -0.13, standard error = 0.02).

Parameter	Compulsory investment (% change)	Optional investment (% change)
Hours Run: Oct-Mar	4.36	7.59
Size of Unit	2.93	5.10
Heat to Power Ratio	0.89	1.56
Winter Downtime	-0.19	-0.32
Maintenance Cost	-1.22	-2.12
Capital Unit Cost	-4.02	-7.01
Discount Rate	-4.44	-7.74

Table 2: NPV elasticity with key parameters[5]

To explain why smaller schemes and optional investments were particularly affected by this decline in adoption, we look at the details of the cogeneration investments.

[5] The magnitude of the elasticity is different for compulsory and optional investments as there is a different base NPV value for each. However the ordering of the elasticities are the same.

Uncertainty and sensitivity analysis was carried out to ascertain the key actors affecting return on investment. To further examine these key factors (including the discount rate), Table 2 details elasticity (dNPV/dx * x/NPV) or the percentage change in NPV for a 1% change in the input parameter(x).

Therefore the key parameters resulting in a greater NPV are more hours run (related to size), larger units, a higher HPR, less downtime (dependent on good maintenance), cheaper maintenance costs, lower capital costs[6] and a lower discount rate. The size and HPR results are in agreement with the statistical results for these parameters.

9. Size of Installations

Figure 4 relates unit size to return on investment. For a compulsory investment case, the minimum size that gives a positive NPV at the 50th percentile is 160kWe (90kWe at the 10th percentile and 270kWe at the 90th percentile). For the optional case with its slightly poorer economics, a minimum size of 200kWe needed for a positive NPV at the 50th percentile (115kWe at the 10th percentile and 320kWe at the 90th percentile). This suggests that the effective lower limit on size is not technical but economic, and that a large number of schemes have been installed under this minimum size threshold[7].

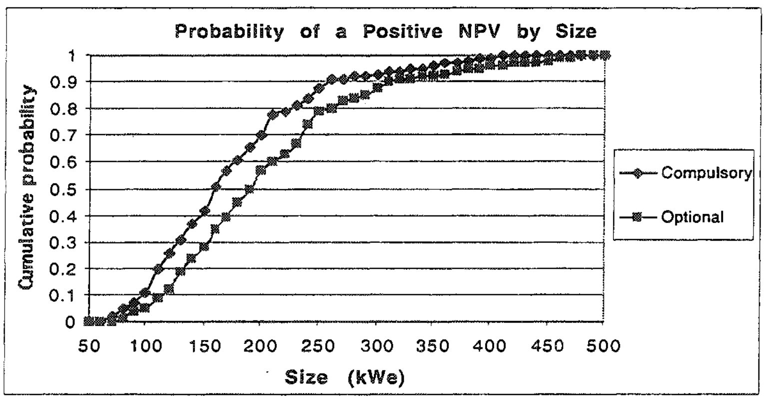

Figure 4: Compulsory and Optional investments vs. unit size

To further illustrate the importance of unit size, Figure 5 details the NPV (at the 50th percentile) for a low load factor (5,200 hrs per year, such as an office), and a high load factor (6,800 hrs per year, such as a hospital). For the hospital sector whose high load factor sites have seen significant penetration, the minimum economic size is 125kWe for a compulsory investment and 155kWe for an optional investment. However, for the office sector whose low load factor sites have not seen significant penetration, the minimum economic size is much higher at 205kWe for a compulsory investment and 240kWe for an optional investment.

[6] Capital costs of engine cogeneration units did not change through the period of study.
[7] As seen in Table 2, NPV is dependent on changes in parameter values, (for example if a discount rate of 10% is used instead of 15%, then the minimum size thresholds become 110kWe for a compulsory and 130kWe for an optional investment).

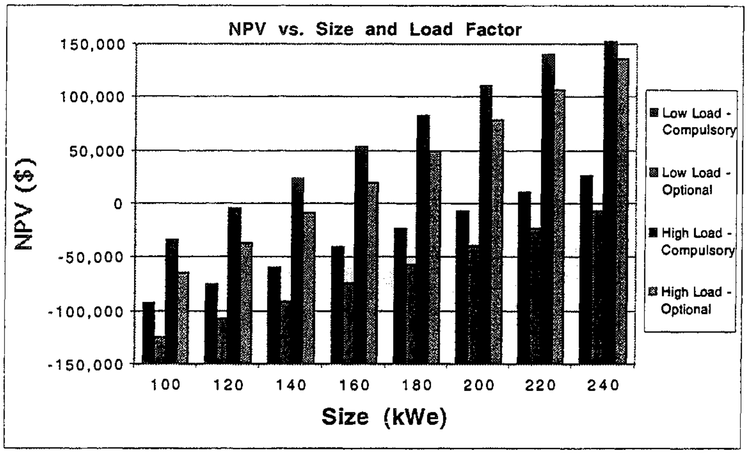

Figure 5: NPV vs. size and load factor

Therefore, this minimum size for positive NPV reiterates that many optional and compulsory cogeneration installations have not been good investments. Sensitivity analysis shows that under all realistic expectations of electricity and gas prices, the majority of investments are still poor investments. In addition, this result indicates that the calculated potential for engine cogeneration, which rests heavily on penetration of low load applications such as offices and retail buildings, may be too high.

10. Maintenance of Installations

Figure 6 shows the NPV at the 50th percentile for different maintenance costs and sizes of installations, for a compulsory and optional investment respectively. The results show the effect of maintenance costs on the minimum size of unit for a positive NPV. Typical maintenance costs are consistent at $20,000 and are thus proportionally larger for smaller sized units. (Adopters did not expect maintenance (or capital) costs to change in the near future).

At a maintenance cost of $20,000, minimum economic sizes are 160kWe for a compulsory investment, and 200kWe for an optional investment. If the maintenance cost could be reduced to $12,000 then 120kWe units for a compulsory investment and 160kWe units for an optional investment would be economic. Therefore, the minimum size threshold is driven in part by the fixed maintenance costs.

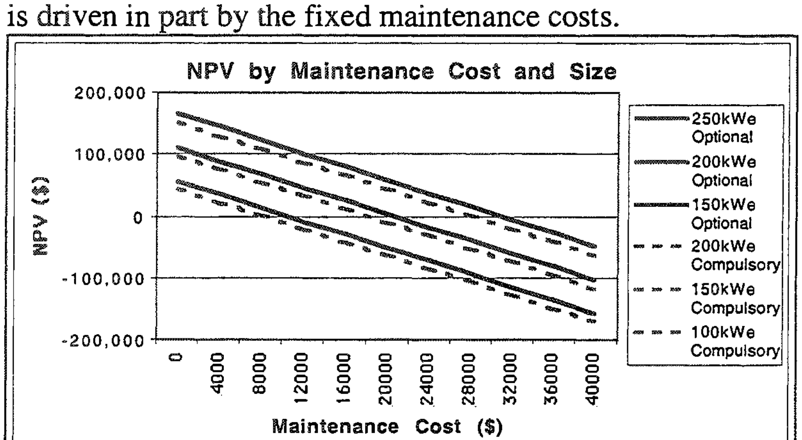

Figure 6: NPV by maintenance cost and size for a compulsory investment

11. Financing of Installations

Table 3 shows the percentages of schemes financed by the adopter's own capital or through a supplier financed lease option. Both options entail a long term commitment. The number of total schemes financed by either method are approximately equal, but for a compulsory investment the adopter is more likely to use its own capital (80% of schemes), whilst for an optional investment with its correspondingly poorer return, the supplier finance option is more common (60% of schemes).

		INVESTMENT		
		Optional	**Compulsory**	**Total**
FINANCE	**Self**	35%	12%	47%
	Supplier	50%	3%	53%
	Total	85%	15%	100%

Table 3: Financing of investments based on type of investment and type of finance

Figure 7 further investigates this by stratifying the type of financing chosen by the size of unit. For compulsory investments, supplier finance is uncommon and large schemes (>150kWe) are more prevalent than small schemes (<150kWe). For optional investments, small schemes are more common, and 64% (+/- 8%) of small schemes are supplier financed compared to only 35% (+/-10%) of large schemes being financed by suppliers.

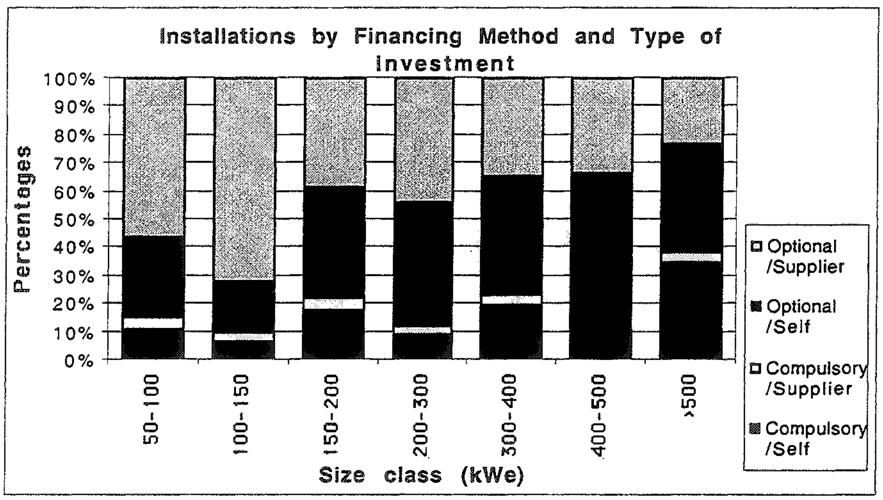

Figure 7: Financing options based on type of investment and size

Therefore, supplier financing is geared towards supporting installations with poorer returns, either small schemes and/or optional investments[8]. Supplier financed schemes below the minimum size threshold for a positive NPV are not a source of sales revenue, but these schemes do provide a stream of income.

[8] It is likely that the supplier's capital cost for cogeneration installations is less than the sale price. At a cost of 70% of sale price, 115kWe units for compulsory and 130kWe units for optional investments generate sales revenue for suppliers.

59% of self financed schemes and 80% of supplier financed schemes are not justifiable under reasonable assumptions[9], as they fall below the minimum threshold for positive NPV(160kWe for compulsory investments and 200kWe for optional investments). The remaining installations can be considered reasonable. Therefore the merits of the majority of both self financed and especially supplier financed schemes for adopters are questionable.

12. Conclusions and Policy Implications

This detailed analysis of engine cogeneration shows the majority of early adoptions of this decentralized energy technology were not good investments under reasonable assumptions. There is an effective lower size threshold (160kWe for a compulsory investment and 200kWe for an optional investment in energy capital) for a positive NPV on investment. As a result of this lower limit the adoption of smaller schemes declined dramatically, and the overall potential (based on single site applications with no electricity export) of this technology is reduced.

A regulatory policy implication to overcome this minimum size threshold is to facilitate installations serving multiple sites by allowing economic returns on export of electricity, thus removing the monopsony power of the electricity utility. Other important factors determining the cost effectiveness of the unit are hours of operation, and correct matching to a site's energy requirements (HPR) which further support the case for multi-site applications to ensure consistent load factors for this decentralized technology.

One significant determinant of the lower size threshold is the fixed costs of maintenance. Good maintenance is essential for the unit to achieve its projected savings and also to be viewed as a dependable technology to meet electricity and heat requirements. Given that maintenance is key to this well established technology's performance and cost effectiveness in a developed country, a technological policy implication is to have minimal maintenance requirements for economic operation and hence adoption of decentralized energy technologies. This is especially relevant to technologies that are less mature and/or are being deployed in countries with a less developed technical support base.

The decrease in adoption of engine cogeneration can be explained by decision makers satisficing on comparable savings in energy costs with no capital investment following the deregulation of the UK energy market. Other explanations could be that decision makers learnt from previous poor investments or that the supply side of this emerging market was inexperienced. Further research aims to explore these postulated explanations for the decline in early adoption of engin cogeneration.

Installations with better returns (compulsory capital investments and larger schemes) are more likely to be self-financed. However, 59% of self financed schemes, and 80% of supplier financed schemes are not justifiable under sensible assumptions. The remaining installations can be considered reasonable for adopters. Supplier financed schemes below the minimum size threshold may not be a source of sales revenue, but these schemes do provide a stream of income. Energy services and joint ventures in a deregulated market have been supported as a key way to promote decentralized energy supply, because it changes a

[9] Adopters would need to expect the electricity price to rise to 10c/kWh for 100kWe and 130kWe schemes to be justified for compulsory and optional investments respectively. Instead the electricity price fell from 7.3c/kWh to 6.3c/kWh.

discretionary investment for the adopter into a core investment for the supplier. However, the case of engine cogeneration illustrates that adopters may not always make good energy services investments in decentralized energy technologies. A policy implication to improve decision making is to build up a successful track record of energy services agreements for both suppliers and adopters, possibly through the commitment of public sector organizations.

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