



The Open University

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1. General Introduction and Summary

The Open University Energy and Environment Research Unit has, since its foundation in 1986, focussed on a range of sustainable energy technologies on a variety of scales, from large to small, in the belief that a sustainable energy system will require contributions at all scales. So while we support, for example, the development of microgeneration and improvements in energy efficiency in buildings, we also believe that larger-scale projects, in particular offshore wind and city-wide combined heat and power (CHP), have a major role to play in a sustainable energy future.

This submission is in two parts:

Part One proposes a major expansion in the UK's offshore wind programme.

Part Two proposes a major expansion in Combined Heat and Power (CHP).

Key points made in this submission are as follows:

Part One, Offshore Wind: Key Points

- By 2024, a major offshore wind programme could be supplying 26% of UK electricity and saving nearly 6% of carbon emissions
- In comparison, an expanded nuclear programme might supply some 23% of current demand and displace some 5% of carbon emissions by 2024
- With some additional pump-priming support from Government for a limited period, offshore wind energy can progress rapidly down the learning curve to lower costs
- The cost of electricity from offshore wind after 2020 is likely to be no more, and possibly slightly less, than that from nuclear power, including the additional costs of reserve power to cope with the variability of wind
- An expanded offshore wind industry could support some 50,000 jobs, offsetting the decline in the UK's offshore oil and gas industries and utilising established UK skills and experience in offshore engineering
- Government should consider establishing a public-private partnership to boost the development of offshore wind, in particular to fund long-term investment in offshore grid connections

Part Two, Combined Heat and Power: Key Points

- A long term goal to make use of 50% of the waste heat from the UK's electricity industry could save at least 10% of the nation's CO₂ emissions
- CHP reduces the overall demand for gas, particularly the peak winter demand, reducing the need for liquefied natural gas storage.
- CHP plant is not 'baseload'. With added heat storage, it can act as a flexible complement to variable renewable energy supplies.
- The marginal cost of heat from CHP plant can be very low. Community heating and CHP in inner city areas can be a cheaper solution to affordable heating than some programmes of retrofit insulation in existing homes.
- CHP is also likely to provide a cheaper option than electric resistance heating in new homes.
- Distributed generation using CHP will reduce the need to reinforce the electricity grid and build yet more pylons.
- Making use of waste heat from inland power stations will conserve valuable water otherwise lost in cooling towers.

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- The construction of heat grids creates employment: UK labour and (hopefully) UK-produced pipework are substituted for imported gas.
- The availability of heat grids allows future fuel flexibility including the use of waste heat from industry, biofuels, waste incineration and even solar energy. Also if the government chooses to follow a nuclear route, the use of waste heat from nuclear power stations could become an option.
- Gas fired CHP is less sensitive to changes in variations in gas prices than electricity-only generation plant. If the gas price goes up, then so does the value of the heat produced.
- It is impossible to have a 'market in heat' without first constructing the heat grid marketplace.

2. Part One: The Potential for a Large-Scale UK Offshore Wind Energy Programme

2.1 Introduction

The United Kingdom has been called the Saudi Arabia of wind energy. The winds that blow across our surrounding seas have the potential to supply several times the nation's electricity requirements. This potential has only just begun to be tapped.

But current offshore wind expansion is progressing much too slowly.

Britain needs to seize the opportunity to create a world-class offshore wind industry, installing many thousands of megawatts of offshore generating capacity in a mutually-beneficial partnership between private and public sectors, following the example of the successful offshore oil and gas industries of the 70s and 80s. In less than 20 years' time, offshore wind could be supplying a quarter of UK electricity and supporting many tens of thousands of jobs, in a major new 'sunrise' industry with significant export potential.

2.1.1 The BWEA Report

This part of the submission is relatively brief because it builds upon and extends the excellent report by the British Wind Energy Association (BWEA) *Offshore Wind: at a Crossroads* (BWEA, 2006). This demonstrates convincingly that, with moderate additional 'pump-priming' support over the coming decade, offshore wind capacity could rise to some 8 GW by 2015, supplying some 6% of UK electricity.

The BWEA report identifies a number of significant problems affecting the UK offshore wind industry. These include substantial increases in wind turbine prices due to greatly increased world demand, higher costs due to inadequate reliability of current turbines (mostly designed for onshore use) in an offshore environment, higher world prices of raw materials, and uncertainty regarding grid connection costs. Further deterrents to offshore development include the long-term uncertainty in the value of Renewable Obligation Certificates beyond 2015, and the possibility that other renewable energy options may become more attractive investments than offshore wind.

The BWEA concludes, following extensive consultation with the offshore wind developers, is that there is "an economics gap of up to around 25% of installed project cost." The additional support required could take the form of additional capital grants, of around £0.3 million per MW; or it could take the form of enhanced price support for offshore wind under the Renewables Obligation (RO). One way of achieving the latter, suggested by the Scottish Executive, would be to assist offshore wind and other marine renewables by offering them double Renewable Obligation Certificates for each MWh of electricity generated. Although the BWEA does not propose this, it seems reasonable to suggest that any additional costs of offshore RO support could be offset by a commensurate reduction in RO price support for on-shore wind, which has already achieved commercial viability. Other forms of support, such as long-term Government financing of offshore grid connections, are also possible – see below.

If such support is not forthcoming, however, the BWEA concludes that UK offshore wind capacity will probably grow very slowly, to only around 2GW by 2015. This rate of deployment would not be sufficient to give suppliers, contractors and utilities the necessary confidence to make the major investments required to achieve economies of scale and long-term cost reductions.

2.2 Current Offshore Plans: Rounds 1 and 2

There are currently three UK offshore wind farms, at North Hoyle, Kentish Flats and Scroby Sands, with a total capacity of 210 MW. During 2006, an additional 190 MW of offshore capacity should be completed. Beyond this, the DTI's initial 'Round One' offshore plans envisage an expansion to around 1000 MW over the next few years.

The DTI's 'Round Two' offshore wind plans are more ambitious, involving some 15 additional offshore wind farms, some of them of over 1000 MW capacity, building up to a total capacity of some 7.2 GW. The timescale for this is still very uncertain, however.

2.3 Beyond Rounds 1 and 2: Further Major Offshore Expansion

The BWEA's "New Policy Impetus" Scenario envisages offshore capacity growing, with the benefit of additional support, to some 8 GW by 2015, by which time Rounds One and Two would be completed and an additional 'Round Three' of construction would have started around 2013. Installed capacity would rise to 8 GW by 2015 and around 10.5 GW by 2017, with annual growth rates increasing to around 1.2 GW per annum by early in the next decade.

This submission suggests, however, that it is entirely feasible for growth rates to be rather higher than this, and for the expansion in offshore wind to continue beyond the 2015-2017 period envisaged by the BWEA.

The Scenario illustrated in Table 2.1 below, although similar to the BWEA's in its first decade, is more optimistic. The number of turbines installed per year builds up from 90 in 2006 to 400 in 2015. The size of turbine installed also increases gradually, in line with the steady growth in turbine sizes seen in recent years, from the present 3 MW to 5 MW by 2012. Five megawatt machines have already been demonstrated by several European manufacturers, and the BWEA scenario also envisages such turbines coming into use early in the next decade. (Even-larger offshore turbine sizes are considered likely by many experts, but are not considered in this scenario). Annual capacity factors for the offshore wind farms in the scenario are projected to rise slightly as technology and operational experience is gained, from 0.36 (the capacity factor achieved in the UK's first offshore wind farm, North Hoyle, in its first full year of operation) in 2006 to 0.38 by 2024.

The scenario in Table 2.1 envisages annual installation rates increasing to 2GW per annum by 2015 (equivalent to 400 5 MW turbines per year) and continuing at that rate until 2024. A deployment rate of 2 GW per annum is not unrealistic: it is the average rate at which wind turbines (each averaging only 1 MW capacity) have been installed in Germany in recent years (Deutsche Energie-Agentur, 2006); and it is slightly less than the rate of installation in the USA in 2005, which was 2.4GW. By 2015, the scenario envisages some 10 GW being installed, compared to 8 GW in the BWEA scenario. Beyond that date, it shows further strong growth in offshore capacity, building up to some 28 GW by 2024.

The programme envisaged would involve the installation of around 6,000 offshore turbines in 18 years, ranging in size from the current 3 MW to the 5 MW size expected after 2012. Notionally, these could be located in, say, 30 arrays of 200 turbines each. There is no shortage of space for such arrays in the UK's extensive surrounding seas, allowing room for shipping lanes, fishing, defence radar exclusion zones and other uses.

2.4 Contribution to Electricity Supplies & Carbon Savings

By 2024, the projected 28GW of offshore wind generating capacity would be producing some 94 TWh annually, just over 26% of current annual UK electricity demand, and saving some 5.7% of the nation's current annual carbon emissions (compared with emissions from an equivalent Combined Cycle Gas Turbine plant).

Table 2.1

Proposed Major UK Offshore Wind Power Programme: Timing, Capacity, Output, % of Electricity, C Savings <i>Scenario 1: Rapid buildup to c. 2GW p.a. by 2015 then constant to 2024</i>										
Year	Turbine Size (MW)	Turbines per year	Total No. Turbines	Capacity Added (Gw/yr)	Total Wind Capacity (GW)	Capacity Factor	Annual Output (TWh)	Percent of UK Elec Demand	Annual C Savings (MtC)	Percent of UK C Emissions
<i>NOTES</i>	<i>1</i>	<i>2</i>				<i>5</i>	<i>6</i>	<i>7</i>	<i>3</i>	<i>4</i>
2006	2.5	90	90	0.2	0.2	0.36	0.7	0.2%	0.1	0.0%
2007	2.9	120	210	0.3	0.6	0.36	1.8	0.5%	0.2	0.1%
2008	3.3	150	360	0.5	1.1	0.36	3.4	0.9%	0.3	0.2%
2009	3.7	180	540	0.7	1.7	0.36	5.5	1.5%	0.5	0.3%
2010	4.2	210	750	0.9	2.6	0.36	8.3	2.3%	0.8	0.5%
2011	4.6	240	990	1.1	3.7	0.37	12.1	3.4%	1.2	0.7%
2012	5.0	270	1260	1.3	5.1	0.37	16.4	4.6%	1.6	1.0%
2013	5.0	300	1560	1.5	6.6	0.37	21.3	5.9%	2.1	1.3%
2014	5.0	350	1910	1.7	8.3	0.37	27.0	7.5%	2.6	1.6%
2015	5.0	400	2310	2.0	10.3	0.37	33.4	9.3%	3.2	2.0%
2016	5.0	400	2710	2.0	12.3	0.38	41.0	11.4%	4.0	2.5%
2017	5.0	400	3110	2.0	14.3	0.30	37.6	10.4%	3.6	2.3%
2018	5.0	400	3510	2.0	16.3	0.37	52.9	14.7%	5.1	3.2%
2019	5.0	400	3910	2.0	18.3	0.37	59.4	16.5%	5.8	3.6%
2020	5.0	400	4310	2.0	20.3	0.38	67.6	18.8%	6.6	4.1%
2021	5.0	400	4710	2.0	22.3	0.38	74.3	20.6%	7.2	4.5%
2022	5.0	400	5110	2.0	24.3	0.38	80.9	22.5%	7.8	4.9%
2023	5.0	400	5510	2.0	26.3	0.38	87.6	24.3%	8.5	5.3%
2024	5.0	400	5910	2.0	28.3	0.38	94.2	26.2%	9.1	5.7%

NOTES

- 1. Average capacity of turbines installed in given year; increases from 2.5 MW to 5 MW by 2012*
- 2. Rapid linear increase in numbers from 2006 to 2015, then constant thereafter*
- 3: Based on offsetting C emissions from CCGT @ 97tC/GWh = 0.097MtC/TWh*
- 4. Current Total UK C emissions: c.160 MtC*
- 5. Excludes ON-shore wind capacity: currently c. 1GW*
- 6. Assumes gradual increase in offshore CF from current 0.35 to 0.38 by 2024 (conservative)*
- 7. Current UK Elec demand: c. 360 TWh*

2.5 Comparison with a Major Nuclear Programme

Table 2.2 shows the possible progression of a major nuclear expansion programme in the UK over the next two decades. Assuming a go-ahead by Government in principle in 2006, and three years for Parliamentary approval, licensing, planning permission etc., construction of the first PWR might commence in 2010 and take five years. Ten stations of the Westinghouse AP1000 type are envisaged, each with a generating capacity of 1.1 GW, and built at a rate of one per year. The annual average capacity factor of the installed nuclear power plant is projected to rise from 75% in 2015 to 85% by 2024. By that date, the 11 GW programme could be complete and generating some 82 TWh of electricity per year, some 23% of current demand, and saving some 5% of the UK's current annual carbon emissions (compared with emissions from an equivalent CCGT).

Table 2.2

Major UK Nuclear Expansion Programme, 2006-2024: Output; % of UK Elec & C Emissions.									
Year	Plant Capacity (GW)	No. of Plants per yr	Capacity Added (GW/yr)	Cumulative Capacity (GW)	Capacity Factor	Annual Output (TWh)	Percent of Elec Demand	Annual C Savings (MTC)	Percent of UK C Emissions
<i>NOTES</i>	<i>1</i>				<i>2</i>		<i>7</i>	<i>3</i>	<i>4</i>
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015	1.1	1	1.1	1.1	0.75	7.2	2.0%	0.7	0.4%
2016	1.1	1	1.1	2.2	0.76	14.6	4.1%	1.4	0.9%
2017	1.1	1	1.1	3.3	0.77	22.3	6.2%	2.2	1.3%
2018	1.1	1	1.1	4.4	0.79	30.4	8.5%	3.0	1.8%
2019	1.1	1	1.1	5.5	0.80	38.5	10.7%	3.7	2.3%
2020	1.1	1	1.1	6.6	0.81	46.8	13.0%	4.5	2.8%
2021	1.1	1	1.1	7.7	0.82	55.3	15.4%	5.4	3.4%
2022	1.1	1	1.1	8.8	0.83	64.0	17.8%	6.2	3.9%
2023	1.1	1	1.1	9.9	0.84	72.8	20.2%	7.1	4.4%
2024	1.1	1	1.1	11	0.85	81.9	22.8%	7.9	5.0%

NOTES 1. Assumes 3 years from 2006 for permissions; start 1st reactor in 2010; 5 years to first generation; 1 Westinghouse AP1000/yr for 10 yrs
2. Assume mean CF increases gradually from 0.75 to 0.85
3: Based on offsetting C emissions from CCGT @ 97tC/GWh = 0.097MTC/TWh
4. Current Total UK C emissions: c.160 MTC
5. Current UK Elec demand, c. 360 TWh

2.6 Wind Variability: Not a Major Problem

The offshore wind scenario outlined in Table 2.1 would contribute some 94 TWh per annum, 26% of current UK electricity demand. In addition to this, the capacity of on-shore wind farms could well increase from its present value of 1 GW to as much as 10 GW by 2024. Assuming a lower on-shore capacity factor of 0.3, this would produce some 26 TWh annually. Added to the estimated 94 TWh produced by the proposed offshore programme, the total annual output from UK wind power would be some 120 TWh. This would amount to a 33% contribution to current UK electricity requirements.

The UK Energy Research Centre’s study of the additional reserve costs associated with the variability of renewable energy sources, published in April 2006, makes it clear that, contrary to many popular misconceptions, these are relatively modest. For a 20% contribution of wind energy to the grid, the additional cost is around 0.3p/kWh; and for a wind energy contribution of up to 45%, the study suggests that the additional costs are unlikely to exceed 0.5p/kWh. (UKERC, 2006)

2.7 Monetary Costs: Wind vs Nuclear

The Cabinet Office's Performance and Innovation Unit (now the Prime Minister's Strategy Unit) in its 2002 Energy Review estimated that by 2020 the generating cost of electricity from offshore wind would be some 2.0-3p/kWh, compared to that of new nuclear plant at 3-4 p/kWh (PIU, 2002). These costs are in constant 2002 prices and take into account, for both wind and nuclear, repayment of capital costs, interest on capital, fuel costs, and operation and maintenance costs. They also take into account the cost reductions that are achievable through large-scale series production and deployment, as each technology progresses down the 'learning curve'.

The UK Energy Research Centre's intermittency study, quoted above, would suggest that some 0.5 p/kWh should be added to the generating costs of the major offshore wind programme proposed in this submission, in order to allow for additional reserve costs. This would increase the generating costs of offshore wind power to around 2.5-3.5 p/kWh. This is still somewhat lower than the PIU estimate of 2020 nuclear generating costs, at 3.0-4.0 p/kWh. (The PIU cost estimates do not appear to include the cost of grid strengthening, which would be required for new, large-scale generating programmes, whether wind or nuclear). However the figures are very close and the uncertainties inherent in such projections would suggest that the actual generating costs in the early 2020s of offshore wind and nuclear power would probably be very similar.

2.8 Employment

It is estimated that some 50,000 people are currently employed in the German wind energy industry supporting an installation rate, as mentioned above, of around 2 GW per annum (Deutsche Energie-Agentur, 2006). It seems reasonable to assume that the 2GW p.a. installation rate proposed for the UK in this submission would generate a similar number of jobs. Unlike Germany, the UK at present does not have any major wind turbine manufacturers, but if a major offshore wind programme were implemented, UK-based manufacturing could revive; or employment-creating joint ventures between UK and other EU firms, such as that between Germany's REpower and the UK's Peter Brotherhood, could be established. In any case, apart from turbine manufacture, there would be many thousands of jobs in assembly, delivery, installation, connection and servicing of offshore wind farms. The creation of such an industry would ensure continuing employment in the UK offshore sector, as our reserves of oil and natural gas decline.

2.9 A Public-Private Partnership?

Government could, as the BWEA has suggested, greatly assist the offshore wind industry in moving beyond its current pioneering phase toward maturity, and eventually achieving lower costs, by giving additional capital grant support to Round One and Round Two projects or by allocating additional revenue support to offshore wind under the RO.

Another way in which support could be given would be through the creation of a public-private partnership to build the new electrical infrastructure that will be required to connect a substantial number of offshore wind farms, and other marine technologies such as wave and tidal power, to the national grid.

This would, of course, involve additional public sector borrowing by the Treasury, but as the current Chancellor of the Exchequer has repeatedly emphasised, public borrowing for investment is a sound and prudent use of taxpayers' money. The capital cost of offshore grid infrastructure could be raised by issuing Government-backed bonds. This capital expenditure would be repaid over the lifetime of the assets created, say 25-30 years, at the low interest rates at which Governments can borrow money, typically around 5-6%. Repayment could take the form of a levy on each unit of electricity sold by the offshore wind farm operators. The construction and operation of the offshore wind farms themselves would be left to the private sector, as at present.

As Eddie O'Connor, managing director of the wind farm developer Airtricity (which built Ireland's first offshore wind farm at Arklow Bank, and plans to construct a 500 MW offshore wind farm at Greater Gabbard in the Thames Estuary) has pointed out, the suggestion that Government should fund basic infrastructure for long-term public benefit is hardly a new one:

“Henry Ford quite rightly refused to contribute to building the roads. He judged that society should pay for them.(...) It is quite appropriate that offshore grids should be paid for by the government. If you want a new technology you should not over-burden it with costs.” (quoted in Massy, 2005)

This principle was also enunciated well before the era of Henry Ford, by that pioneering advocate of the market economy, Adam Smith:

“The sovereign (government) has the duty of erecting and maintaining certain public works which it can never be in the interest of any small number of individuals to erect and maintain; because the profit could never repay the expense to any small number of individuals, though it may frequently do much more than repay it to a great society.” (Adam Smith, *The Wealth of Nations*, 1776.)

2.10 Conclusions (Part One)

The UK’s first offshore wind farms are up and running. With the right support from Government over the next two decades, they could be followed by many more.

By around 2024, a vigorous programme of offshore wind deployment could be delivering some 26% of UK electricity and saving nearly 6% of UK carbon emissions, compared with 23 % of electricity and 5% carbon savings from a programme of 10 nuclear power plants. With adequate initial support, the cost of electricity from offshore wind by 2020 is likely to reduce, through the economies of large-scale deployment, to approximately the same level as that from nuclear power, or possibly slightly less, even allowing for the additional costs of reserve power to back-up wind supplies. The proposed size, timescale and electricity generating costs of the offshore wind programme proposed here may seem somewhat optimistic, but they are no more so than the size, timescale and costs of a comparable new nuclear programme.

The challenges facing the 21st century UK offshore wind industry in the demanding marine environment may be substantial, but they are no more insuperable than those faced by the offshore oil and gas industry in the 1970s and 80s. By the early 2020s, given a mutually-beneficial partnership between Government and industry, Britain could boast a world-class offshore wind industry supporting around 50,000 jobs, offsetting the decline in UK’s offshore oil and gas industries, and with excellent export potential.

2.11 References (Part One)

BWEA (2006) *Offshore Wind: at a Crossroads*, British Wind Energy Association, April, 16pp.

Deutsche Energie-Agentur (Germany Energy Agency) website: <http://www.renewables-made-in-germany.com/>

Massy, J. (2005) “Turbulent Waters Create Market Drag”, *Windpower Monthly*, April, pp 45-52.

PIU (2002) *The Energy Review*, Performance and Innovation Unit (now Prime Minister’s Strategy Unit), Annex 6: The Potential for Cost Reductions and Technological Progress in Low Carbon Technologies, pp 189 -199. UK Cabinet Office Report.

Smith, Adam (1776) *The Wealth of Nations*.

UKERC (2006) *The Costs and Impacts of Intermittency*, UK Energy Research Centre, London SW7 2PG, see in particular Section 3.3, Figure 3.2, pp 37-40.

3. Part Two: The Need for a Large-Scale UK Combined Heat and Power Programme

3.1 Introduction

It is extremely unlikely that the UK will reach 60% CO₂ emission cuts by 2050 without embracing a serious, Danish-style programme of large-scale Combined Heat and Power (CHP) generation. This will involve using the waste heat from power stations (of many different sizes) to heat the building stock by the use of community heating (otherwise known as district heating). It will require the construction of heat distribution grids in all cities and most large towns.

3.1.1 The Basics of CHP

A typical coal-fired power station is only about 35% efficient in terms of electricity generation, the rest of the fuel energy being lost in cooling towers, dumped in rivers or the sea and lost as heat in the transmission grid. Nuclear power stations have a slightly better performance but modern gas fired combined cycle gas turbine (CCGT) plant can have electrical efficiencies of 45-50%. Combined heat and power plant has lower electrical efficiencies, but makes use of the waste heat in industrial processes or for heating buildings. Its overall useful fuel efficiency can be 80% or higher (see figure 3.1 below).

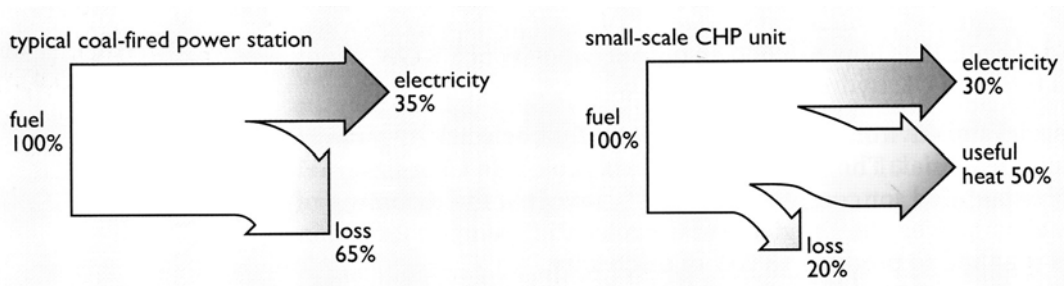


Figure 3.1 Energy flows through a typical coal-fired power station and a CHP unit

There are many options for CHP plant:

- using waste heat from existing large power stations
- large, purpose-built CCGT plant of 50 megawatts electrical output (50 MWe) or more. These are used in UK industry and in Denmark to feed large district heating schemes.
- Medium-scale CHP (smaller gas and steam turbines in the range 1 MWe to 50 MWe, and large reciprocating gas or diesel engines in the range 1 to 5 MWe). These again are used in industry and for district heating schemes. Mostly these are fuelled by gas, but there is some waste incineration and biomass-fuelled plant in this range.
- Small-scale CHP (mostly gas and diesel engines in the range 40 kWe to 1 MWe). These are used for heating individual buildings or estates.
- Stirling engine domestic micro-CHP of around 1 kWe. These are designed as gas boiler replacements for individual houses and are still only in the early days of marketing.

At present over 90% of the CHP capacity in the UK is in industry. In 2004 only 6% of the capacity was in buildings. This in contrast to Denmark where over a half of the heat for the country's housing came from CHP (DEA, 2005).

3.1.2 Key Benefits of CHP

For simplicity this submission will concentrate on gas as the main fuel for CHP, but there is important scope for other fuels, particularly municipal solid waste and biomass. There are many advantages of a programme of using CHP compared to a mixture of gas-fired electricity-only generation and gas boilers for heating:

- it reduces overall gas demand and national CO₂ emissions
- it reduces peak winter gas demand and the need for liquefied natural gas storage
- it can produce low-cost heat which can be used to reduce fuel poverty
- many gas-fired power plants can also in an emergency be run on light heating oil, which can easily be stored locally
- more CHP distributed generation would reduce the need to reinforce the electricity grid
- similarly it would restrict the rise of the use of electricity for purely heating purposes, which would require reinforcement of the electricity grid
- the electricity price from gas-fired CHP plant is less sensitive to variations in gas price than electricity-only plant. If the gas price goes up, then so does the value of the heat output.
- reducing the heat lost at cooling towers will conserve valuable water resources
- medium to large CHP schemes equipped with heat storage could act as flexible generation plant to complement variable renewable energy sources such as wind or tidal power.
- distributed small-scale CHP could act as local emergency back-up generation in the event of grid failure. The economic benefits of this could be considerable.

3.2 CHP: The Overall Potential

The scale of national energy wastage in the UK is enormous. As shown in figure 3.2 below, UK total primary energy consumption was nearly 10 EJ in 2000 (about 230 million tonnes of oil equivalent), yet only 6.8 EJ were actually delivered to the consumer. Over 3 EJ (31% of the primary total consumption) were lost in conversion and delivery. Of this about 2 EJ were lost as waste heat by the electricity industry, pumped into the sea, rivers or the air. This figure should be compared with the total delivered energy use for low temperature space and water heating of approximately 2.4 EJ.

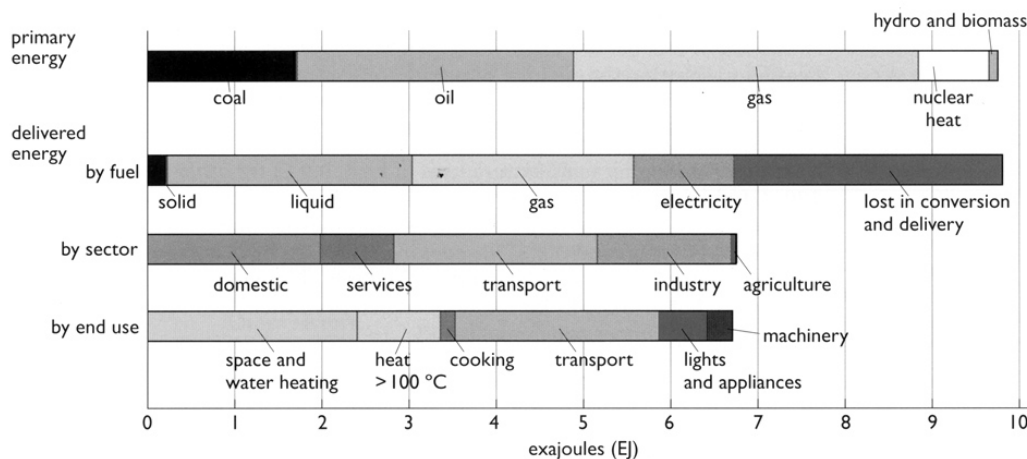
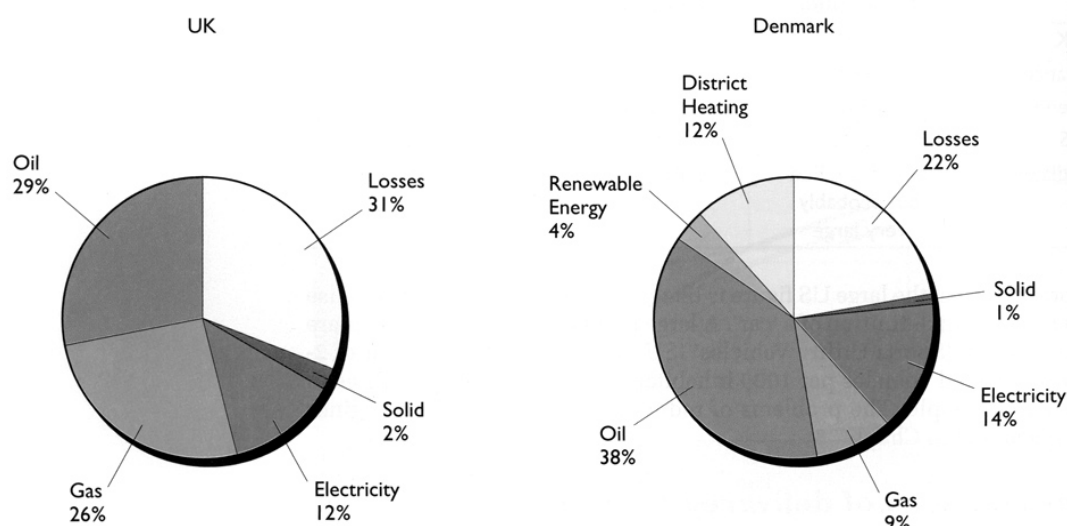


Figure 3.2 UK primary and delivered energy use for 2000 (sources DTI, 2001a, DTI 2001b)

Yet in Denmark, the comparative figure was only 22%. (see figures 3.2 and 3.3 below)



Figures 3.3 and 3.4 Delivered energy and losses for UK and Denmark, 2000 (Sources DTI, 2001a, Danish Energy Authority, 2001)

The key difference is that in Denmark 12% of primary energy consumption was diverted into district heating, with over 50% of electricity coming from CHP plant. In the UK only about 7% of electricity was generated by CHP. When this use of waste heat is taken into account, the Danish electricity supply system achieved an overall fuel efficiency of about 63%, compared to a UK figure of only 40%.

If UK primary energy losses in 2000 had been cut from 31% to the Danish figure of 22%, the national primary energy savings would have been about 0.9 EJ. If this energy could have been usefully substituted for gas-fired low temperature heating, then there would have been carbon emission savings of approximately 14 million tonnes per year, almost 10% of the total for that year. Gas use would have been cut by a quarter. The carbon savings could be considered to be even higher if the CHP generated electricity were used to substitute for electricity from coal-fired stations.

Making use of this wasted energy can be seen as analogous to the position in the early 1970s when natural gas equivalent to the entire UK gas consumption was being flared off on North Sea oil rigs. It took concerted government action to create the gas grids to bring this gas ashore and convert the whole UK gas infrastructure from town gas made from coal.

The carbon saving figure of 14 MtC above, which would seem reasonable given current Danish practice, is in stark contrast to UK government projections. The Consultation Document says (page 54) that *'Large-scale CHP investments have the potential to save around 3 MtC by 2020. But progress has been slower than expected and the cost of CHP remains relatively high'*.

Progress has indeed been slow. The government set a target of 10,000 MWe of CHP capacity by 2010. Capacity has increased from 3,100 MWe in 1995 to about 4,900 MWe in 2003. The government's Strategy for CHP to 2010 (DEFRA, 2004) has admitted the target would not be met and that only about 8,500 MWe might be installed by then.

This potential figure of 3 MtC for 2020 is an extremely low one. It has to be qualified by

- the financial criteria used in assessing the potential
- the published figures for detailed potential
- the assumed figures for carbon savings

3.2.1 Financial Criteria and Investment in Heat Grids

The Consultation Document says that *'The Energy White Paper left open the option of nuclear new build'* but does not comment on the financial criteria necessary for that to happen. Nuclear power is a high capital cost technology with long construction times and long project lifetimes of 40 years or even more. This is contrast

to the main competing electricity generation technology, gas-fired CCGT plant, which has relatively low capital costs and project lifetimes of 20-25 years. The history of the UK electricity industry since privatisation in 1989 has shown that CCGTs have been more attractive to financiers than nuclear power.

The proposal for a Sizewell C plant made by Nuclear Electric at the time of the government's Nuclear Review in 1994 claimed that the plant could produce electricity at 2.93p/kWh. Although the calculations used a discount rate of 8%, the capital had to be amortised over 40 years (Nuclear Electric, 1994).

If a new nuclear programme is to be considered then it is essential that competing technologies must also be assessed with similar discount rates and lifetimes. Small-scale CHP and industrial CHP have relatively low capital costs and project lifetimes of around 20 years, similar to non-CHP CCGT plant. Big-city community heating schemes, however, require a large investment in heat distribution grids which are also likely to take many years to develop.

The consultation document asks about '*Implications in the medium and long term for the transmission and distribution networks of significant new build in gas and electricity generation infrastructure*', but makes no mention of heat grids. Yet the Royal Commission on Environmental Pollution (RCEP, 2000) commented that reducing the UK's CO₂ emissions '*will also require the large-scale construction of district heating networks, so that advantage can be taken of larger-scale combined heat and power schemes*'.

These urban heat grids are an important new national infrastructure that must be put in place now for future developments. For example, attempts to reduce the amount of municipal waste going to landfill will require the construction of new incineration plant, prime candidates for CHP applications. In the longer term biomass CHP will need to be developed particularly for towns and cities in rural areas. Heat grids will also allow the use of large scale solar heating.

The consultation document mentions a market approach, but it will not be possible to have one in heat without a heat marketplace. In Denmark, heat is now sold on a competitive basis into some heat grids.

Investment in these needs to be considered over the same long timescales as might be used for assessing investment in nuclear power. Attitudes to discount rates have changed considerably since the 1990s, especially since there has been continuing low inflation. The Treasury Green Book (HM Treasury, 2003), for example, suggests a 6% discount rate for public sector organisations. This is made up of a 3.5% Social Time Preference Rate (STPR) dropping to 3.0% longer-term projects with lifetimes in the range 31-75 years, plus allowances for 'optimism bias' and project risk. This risk element is likely to be much lower for CHP than for an alternative investment in nuclear power.

3.2.2 Detailed UK CHP potential

There have been a number of studies of UK CHP potential. One study of potential primarily in industry and the commercial and public sector (ETSU, 1997) looked at a range of scenarios. It suggested a CHP potential in these sectors of 16.8 GWe, using an 8% discount rate but only a 10 year project lifetime.

Another study looked at the UK potential for community heating from CHP (BRE, 2003) in domestic, commercial and public buildings. This concluded that there was a total potential of 18.3 GWe using a 6% discount rate. This study carefully analysed heat load maps of major cities by postcode area. The domestic potential amounts to some 5.5 million dwellings, i.e. about a quarter of the housing stock. The study was based on using reciprocating gas engines, but commented that once large areas were connected there could be economies of scale by switching to using larger CCGT plant. This would in turn make it economic to connect further areas.

The need to progress towards large-scale schemes has been stressed in recent work for the International Energy Agency (PB Power, 2005b):

The comparison shows that in the whole city case the most economically viable CHP system is the City-wide scenario (at a discount rate of 3.5% real). The City-wide CHP/DH system benefits from a high efficiency, low capital cost, CCGT power plant, which more than offsets the additional costs of constructing a city-wide heat network.

The environmental comparison also shows a clear advantage in moving to the CCGT plant at District or City-wide scale, particularly when compared to the Buildings CHP systems. This is because the CCGT is much more efficient in producing electricity than the smaller units even though electricity and heat distribution losses are higher. Even if all of the buildings were fitted with small-scale CHP systems the overall CO₂ reduction would be only 5% compared to a 27% reduction for the City-wide scheme.

Somewhat strangely, the 18.3 GWe BRE figure is omitted from the government's *Strategy for Combined Heat and Power* (DEFRA, 2004). Taking the domestic, commercial and public building potential from the BRE study and the industrial potential from the ETSU study gives a total UK potential of nearly 32 GW.

In addition there is the potential for new (and still relatively experimental) single house domestic micro-CHP plant. A report by the Society of British Gas Engineers estimates potential sales of 9 million units by 2020 (approximately 9,000 MWe) resulting in a claimed cumulative reduction in carbon emissions of 9 MtC (SBGI, 2003). To some extent this overlaps with some of the domestic potential identified in the BRE report, but there is no reason why a large proportion of this potential should not be realised in suburban areas, beyond the economic reach of district heating grids.

3.2.3 Carbon Emission Savings

There seems to be considerable confusion over the potential carbon emission savings of CHP. As shown in figure 3.5 below, coal fired generation has the highest carbon emissions, almost 243 grammes of carbon per kWh generated. The emissions from current gas-fired CCGT plant are less than half of this, 97 gC per kWh. The emissions from gas CHP are quoted as 50 gC per kWh. The emissions from nuclear plant are lower still, about 2-6 gC per kWh (mainly from the energy used in mining the uranium and manufacturing the cement to construct the plant) (Sustainable Development Commission, 2006).

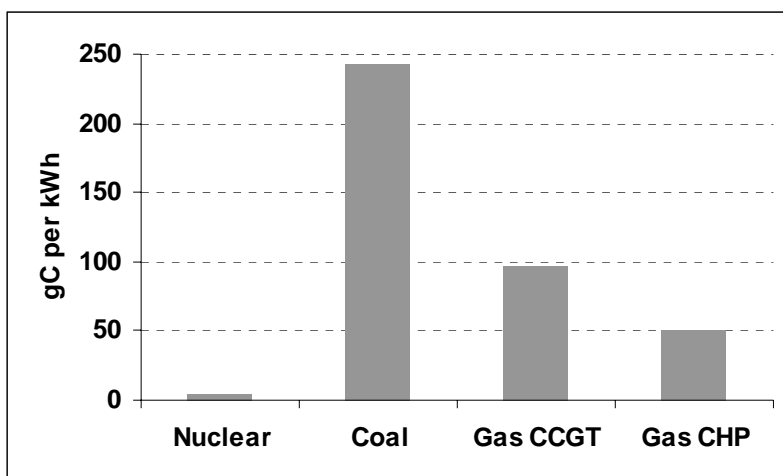


Figure 3.5 Relative carbon emissions from different forms of electricity generation

Government reports such as the *'Strategy for Combined Heat and Power'* have chosen to express the savings in 'million tonnes of carbon saved per 1000 MW of electrical generating capacity of CHP plant' (MtC per 1,000 MWe).

The *'Strategy for Combined Heat and Power'* says that *'In 2002 CHP saved 3.3–4.6MtC, compared to equivalent electricity-only and heat-only generation. This is equivalent to 0.7–0.96MtC per 1,000MWe'*

The report goes on to estimate further savings in the short term up to 2010 at 0.7 MtC per 1000 MWe of CHP capacity, on the basis that new gas-fired CHP plant will be displacing coal-generated electricity.

But then this figure is dramatically revised downwards by a factor of seven: *'Towards 2010 and beyond, CHP is likely to begin to replace new gas-generating technologies compared with which projected savings are 0.1 MtC per 1,000 MWe'*.

The assumption is that new CHP plant will by then be in competition with brand new CCGT electricity-only plant and condensing gas boilers for heat supply. These figures were first published in the DTI's *Energy Trends* in 2003. Since 2003, gas prices have risen sharply, the construction of new CCGT plant in the UK has almost ceased, and the proportion of electricity generated from coal has actually increased. It is thus likely that any new gas-fired CHP plant will continue to displace coal-generated electricity well after 2010.

These figures have been questioned by the Combined Heat and Power Association. A recent report commissioned by them (Minett, 2005) has looked at the carbon savings of a number of CHP options on two bases:

- (a) a most likely displacement approach - i.e. with CHP generated electricity replacing coal-fired generation and the heat replacing existing heating equipment
- (b) an avoided investment approach - with CHP generated electricity replacing that from gas-fired CCGT plant and condensing gas boilers

Some of the key results are shown in Table 3.1 below:

Table 3.1 Carbon savings in MtC per 1000 MWe

	1 kWe Domestic Micro-CHP	1 MWe Hospital Gas-Engine CHP	10 MWe Food Industry Gas Turbine
Most likely displacement approach	1.02	0.72	0.78
Avoided investment approach	0.25	0.26	0.24

The 'most likely displacement' approach gives slightly higher figures (0.72-1.02 MtC per 1000 MWe) than the government's assumed figure of 0.7 MWe per 1000 MWe for CHP potential up to 2010.

However, the figures for the 'avoided investment' approach (0.24-0.26 MtC per 1000 MWe) are much larger than that of 0.1 MtC per 1000 MWe, which must be seriously called into question.

This should be put in perspective by comparing it to the alternative option of nuclear power displacing new baseload CCGT plant. Using the data from figure 5 above, and assuming 85% capacity factors for both, a 1000 MWe baseload nuclear power station would save approximately 0.69 million tonnes of carbon per year.

Taking a figure of 0.25 MtC per 1000 MWe for CHP, we can thus say that 1000 MWe of nuclear plant would have about the same carbon savings as 2800 MWe of CHP. If the potential of 32 GWe mentioned above was achieved there would be carbon savings of about 8 million tonnes carbon.

3.2.4 Security of Supply

Although 'security of supply' is usually taken to refer to supplies of fuel from abroad, there are issues of maintaining electricity supplies in the event of a grid failure (and particularly, more recently, one that might be produced by a terrorist attack). In the current electricity market there is no actual obligation to supply. No-one can held liable for the social consequences of failure to supply. Yet when there is a large-scale blackout there is a genuine large financial and social cost.

The current costs to a company of an electricity failure can be enormous as the following US examples show (US DoE, 2000):

Industry	Average cost of downtime per hour
Cellular Communications	\$41,000
Telephone ticket sales	\$72,000
Airline reservations	\$90,000
Credit Card operations	\$2,580,000
Brokerage operations	\$6,480,000

It is thus not surprising that many organisations have installed emergency backup diesel generators at a cost of around £200-£300 per kW. There is an estimated 20 GW of such plant in Great Britain. Most of this is only for the 'in-house' use of the owners when the grid fails. Somewhat perversely, in order to be reliably available in a power cut, such plant needs to be run regularly on full load to prevent mechanical deterioration. Indeed, once purchased, it might as well be used as part of a CHP system. A system of distributed CHP plants may well be more resistant to a grid failure than relying on supply from a few remote nuclear power stations.

3.2.5 Heat Supply and Fuel Poverty

There has been increasing concern about fuel poverty as a result of rising gas prices. CHP can be a source of cheap low carbon heat supplies. For example a recent urban regeneration study showed that the use of heat from either biomass CHP, local gas CHP or waste heat from a local power station could produce carbon savings at 20% or less cost compared to a programme of retrofit insulation (PB Power, 2005).

3.3 Policies to Promote Large-Scale CHP

3.3.1 The Marshall Studies

The potential for large-scale CHP with district heating was reviewed in the late 1970s by the CHP Group of the Department of Energy under its chairman, Walter Marshall (later Lord Marshall of Goring). This group published two reports, Energy Paper 20 (DoE, 1977) and Energy Paper 35 (DoE, 1979).

These were written at a time when UK electricity was almost entirely produced from coal, the oil price rises of 1973 and 1979 were creating uncertainty about the long term availability of oil for electricity generation, and the large-scale production of North Sea gas was only just starting.

The first points of the Executive Summary are worth re-reading nearly 30 years on:

- 1. We have established that Combined District Heating and Power Generation (CHP/DH) can save energy and could be a viable economic option for heating buildings in areas of high-density heat load, particularly in the longer term.*
- 2. When oil and natural gas are no longer available for heating, the potential for CHP/DH could possibly be in the region of 30 per cent of the existing domestic, commercial and institutional heat load in the UK. The main alternatives to CHP/DH for this market are then likely to be on-peak or off-peak electric heating, SNG [synthetic natural gas] from coal, heat-only district heating, and electricity driven or SNG heat pumps. Heat pumps are however less well developed than most of the other heating methods.*
- 3. If CHP/DH could capture this 30 per cent high-density heat load the approximate savings in primary energy per annum compared to alternative methods of heating could range from about 5 to 30 million tons of coal equivalent (mtce).[i.e. approximately 1.5% to 9% of 1977 total primary energy use]*
- 4. We cannot emphasise too strongly that a prerequisite of having CHP/DH in the future is to develop district heating networks in the meantime. This means making a start with heat-only boiler schemes (and perhaps small sized CHP plant) so that they can be connected up to medium or large CHP plant at a later stage.*
- 5. In the short term, CHP cannot be expected to take off on any scale, largely because of the competition from other fuels, particularly gas. However, if nothing is done to encourage CHP/DH now, we shall not, because of the long lead times, have a CHP/DH option when we need it.*

6. *Therefore in order to have that option available then, we recommend, in spite of the short term difficulties, that a CHP/DH strategy should now be drawn up and implemented, and that an early start on lead-city CHP/DH schemes started if freedom of choice of fuels to consumers is to be maintained. The majority of the Group favoured a Heat Board to take on the national responsibility for CHP/DH.*

The summary went on to point out that about half of the national heat load was associated with Greater London and 80% with the five largest conurbations, viz Greater London, West Midlands, Greater Manchester, Merseyside and Glasgow.

It continued:

The major obstacle will be the competition with other fuels particularly gas during the development phase 10-20 years, and if this is left in the market place we see little chance of CHP/DH schemes taking off at present on their own. No country abroad which has developed CHP/DH has had to overcome such formidable competition from gas.

Despite the urging of this report, the government has consistently refused to set up any kind of 'Heat Board' or coordinating heat authority. Walter Marshall warned that this would be a 'recipe for indefinite delay' for large-scale CHP and so far has been proved right. This in contrast to the vigorous action taken in Denmark at the same time.

3.3.2 Danish Policies

In 1972 Denmark was 72% reliant on imported oil for its energy and was seriously financially embarrassed by the oil price shocks of 1973 and 1979. The result was a policy of moving away from oil-fired electricity generation and central heating to one of energy conservation and the use of coal-fired CHP.

The Danish government took a strongly interventionist approach. New building regulations requiring high levels of insulation were introduced. National heat planning and mapping was carried out in 1981 and in 1982 the Parliament approved public heat supply projects which included an obligatory requirement to connect to district heating. The high price of oil for central heating created a considerable incentive. Later, as Danish North sea gas was developed in the 1980s some coal and oil-fired plant was converted to gas firing.

The overall effect was that between 1972 and 1985 the total area of heated building floor area in the country increased by 30%, but the amount of energy used to heat it decreased by 30% (Dal & Jensen, 2000).

In 1988 electric heating was banned in new buildings and in areas with district heating by natural gas. Successive Heat Supply laws have been used to build up decentralised CHP systems right across the country.

3.3.3 UK CHP since 1980

By contrast, encouragement for UK CHP was relatively weak. One positive act was made in the 1983 Energy Act. Under this Area Boards were obliged not only to 'adopt and support' small scale CHP schemes but also to offer 'avoided cost' tariffs for the purchase of their exported electricity. These reflected the Seasonal Time of Day (STOD) sales tariffs by including high peak winter prices.

Steps were taken in the 1980s to start detailed heat load mapping of major urban areas and to set up lead city CHP schemes. However, Electricity Privatisation in 1989 was a serious blow the growth of large-scale CHP.

Briefly:

- i) the government failed to set up a parallel market in heat to that in electricity. Heat is just as much a tradeable commodity.
- ii) It withdrew obligations on the industry under the 1983 Energy Act.
- iii) It refused to put CHP into the Non Fossil Fuel Obligation (NFFO), on the pretext that the mathematics involved were too complicated
- iv) it claimed that CHP would have a market edge over conventional generation because of the value of the heat. While this is true for small-scale CHP, it is not so for city-wide schemes since it ignores the costs of the distribution pipework and the time taken in setting it up.

- v) it even refused to 'promote' CHP since this was interpreted as meaning giving it a subsidy in a free market.

The effects are best illustrated by the collapse of the city-centre Leicester scheme even as the Privatisation Bill went through Parliament. This 110 MW gas turbine plant was the furthest advanced of the government's 'lead city' schemes and had already consumed £250,000 of government planning money. The Leicester consortium were about to sign a deal for their electricity with the Central Electricity Generating Board when they were told that they must now sell it to the newly privatised East Midlands Electricity who apparently demanded a large cash guarantee that it would go ahead.

After privatisation the Regional Electricity Companies concentrated on building non-CHP gas-fired stations mostly on green-field sites since:

- a) in order to have a competitive presence in the electricity market, they had to have a large power station built as quickly as possible.
- b) given the intensively competitive market, their stations had to be as cheap as possible to build and run. This meant siting them on high pressure gas mains and cheap sites. Choosing city centre sites where heat could be distributed could have been more expensive and entailed planning delays.
- c) building up the heat load for a sizeable CHP power station takes a considerable amount of time and organisation. It requires extra capital expenditure and the monetary benefits might not appear for several years. This could have adversely affect the short-term appreciation of profits and share dividends.
- d) some of the waste heat from the power station would displace electric heating and could be seen as cutting the revenue available from the sale of electricity

Overall, the volatility of the electricity market has created large amounts of financial risk for any particular project. It therefore favours quick-build, low capital cost solutions, requiring the minimum of interfacing contracts.

Although many hold that privatisation and the introduction of the competitive electricity market has been a key factor in giving the current low level of electricity prices, others suggest that prices might have been even lower if the industry had remained under the old CEGB regime (for example Branston, 2000). Other factors, such as the availability of cheap imported coal from the 1980s onwards (at the expense of the UK coal industry) and cheap natural gas with the highly efficient CCGT technology during the 1990s, have contributed to low prices.

3.3.4 The Plight of Small-scale CHP Operators

Small-scale CHP has been heavily promoted in the past by the Department of Trade and Industry as a CO₂ abatement option. As one ETSU report put it 'compared to electricity-only CCGT plant, small-scale CHP has similar capital costs but at the margin uses gas twice as efficiently. Small-scale CHP could therefore achieve CO₂ abatement at zero or negative costs' (Evans, 1990).

The problem is that since about 1991 small independent CHP operators of under 1 MW have only been offered very low prices for their exported electricity. This has had the effect that small-scale systems are being sized only to supply the local building electricity demand rather than to meet the full building heat demand and exporting electricity.

This undersizing may completely undermine the project viability. There are considerable economies of scale. A larger CHP plant is usually more efficient, has lower capital costs per kW and lower maintenance costs than a small one. The practical choice may thus be between a larger plant with export and no plant at all (Everett, 1992).

For all the talk of competitive markets, in practice CHP schemes of less than 500 kW (i.e. enough for about 500-1000 homes) are outside the current electricity market and must attempt to sell their exported electricity as best they can. Schemes in the range 500 kW to 3 MW may access the market through a consolidator, but the consolidator's profit margin will have to be taken into account.

Some serious encouragement is needed.

As noted above, the government has set a target of 10,000 MWe of CHP capacity by 2010, but there is likely to be a shortfall of 1500 MWe. In terms of carbon savings this is equivalent to failing to complete the construction of half of a nuclear power station.

3.3.5 A CHP Obligation?

The government held a CHP strategy consultation in 2002 as a result of which many members of the CHP industry suggested a CHP obligation. The government's response was:

A CHP Obligation would be the surest way to ensure the 2010 target is met. However, it would be relatively expensive in terms of carbon saved, and would not be consistent with the policy to promote a competitive energy market, of both the Government and the European Union.

There are three problems with this view:

- i. There is no doubt that setting up a CHP obligation would cost money, yet its cost-effectiveness can hardly be properly assessed if the CHP potential is under-reported and its carbon savings understated.
- ii. As for consistency with EU policies on competitive energy markets, the Danish answer has always been that protection of the environment is also a key objective of the European Union.
- iii. The key question for this Review is whether or not a programme of nuclear power stations would be competitive with a large-scale one of CHP. Raising the large amount of capital for a nuclear power station may well require guarantees of electricity sales that would be equivalent to a 'nuclear obligation'.

3.3.6 A Feed-In Tariff approach?

The present author would like to see a guaranteed payment system for exported electricity for small plant under 500 kW, essentially a return to the tariffs offered under the 1983 Energy Act. If these payments are a 'fair market price', then they cannot be seen as a subsidy, merely a matter of extending the market price to those outside the market.

This would be analogous to the Renewable Energy Feed-In Tariffs available in many European countries. A recent EU Study (European Commission, 2005) has shown that in promoting wind power 'all countries with an effectiveness higher than the EU average use feed-in tariffs. This type of system currently has the best performance for wind energy'.

A Feed-In Tariff scheme to promote UK small-scale CHP could well be more cost-effective than a CHP Obligation. If this was politically acceptable in 1983, it is difficult to see why it should not be so now.

3.4 Longer Term Issues

3.4.1 Flexible CHP Plant and Variable Renewable Energy Sources

Since the heat load provided by district heating systems peaks in the winter, CHP generation plant is not normally 'baseload'. It is 'middle-merit' plant operating for only part of the day in the summer, but possibly all day and night in the winter. Thus, for much of the year, there is surplus generating capacity which could be called on to complement variable renewable sources such as wind or tidal power or act as backup for other plant in the event of failure.

The flexibility of CHP plant can be significantly improved by installing heat storage. This is widely used in Denmark. It adds about 10% to the capital cost for small schemes and as little as 3% for large ones (EA Technology, 2000). This also creates an opportunity for electrical load management, since the heat stores can be equipped with immersion heaters and used as dump loads at times of grid surpluses or to stabilise the local grid voltage.

Work on the potential for this is ongoing at the University of Birmingham under the EU 'DESIRE' project.

3.4.2 CHP from Biomass, Municipal Waste, Nuclear and Carbon Sequestration Plants

Biomass CHP is successfully used in Denmark. It is odd, however, that in the UK the largest straw-fired power station in the world (38 MWe), situated outside Ely, simply ejects its waste heat into the sky. Consideration needs to be given to making proper use of this waste heat.

Given the shortage of landfill sites, the government has announced an expansion in the number of energy-from-waste plants. It would seem prudent to carry out some research into medium-distance heat transmission (10 km) to allow these plants to be sensitively sited while still making use of their waste heat.

Also, given the problems of nuclear waste and possible future shortage of uranium fuel, it makes little sense to propose a programme of new nuclear power stations which will dump over half of their energy into the sea. Nor does it make sense to propose piping the waste CO₂ from future coal-fired plants with carbon sequestration hundreds of kilometres out into the North Sea without considering piping the waste heat a few tens of kilometres to local urban heat loads.

The Newcastle conurbation has an estimated 440 MW economic CHP capacity, based only using gas engines (BRE, 2003). However this heat load could equally well be met by a coal fired plant with carbon sequestration or by using waste heat from the nuclear power station (and any future replacement) at Hartlepool. Nuclear CHP has been used in Switzerland and Russia. For example the Beznau nuclear plant in Switzerland provides heating for a number of local towns up to 8 km away (Handl, 1998).

The key to these considerations is long distance heat transmission. Energy Paper 35 based its energy calculations on large coal fired plant on the outskirts of cities with main transmission pipes 15 km long. It also considered the option of nuclear CHP situated 50 km from cities. It concluded that this would be considerably cheaper than an alternative option of a major programme of nuclear power to provide on-peak electric resistance heating.

A US paper from the same period (Karheck, 1978) suggested that heat losses from a 56 km long transmission main could be only 1% and the pumping power required would only be 0.5% of the transmitted energy. In practice most of the heat losses in district heating systems are from the small distribution pipes to individual houses.

In the longer term it is vital that any new power plant -- be it biomass, coal with sequestration or even nuclear -- is sited so that its waste heat can be usefully used. This may require research into the economics of long-distance heat transmission.

3.5 Conclusions (Part Two)

There is an enormous potential for the wide-spread use of Combined Heat and Power generation in the UK, as is already done in Denmark and other European countries.

In the long term CO₂ emission savings could be up to 10% of the national total.

To re-emphasize the points made in Section 3.1.2 above:

- CHP reduces overall gas demand and national CO₂ emissions
- It reduces peak winter gas demand and the need for liquefied natural gas storage
- It can produce low-cost heat which can be used to reduce fuel poverty
- Many gas-fired power plants can also in an emergency be run on light heating oil, which can easily be stored locally
- More CHP distributed generation would reduce the need to reinforce the electricity grid
- Similarly, CHP would restrict the rise of the use of electricity for purely heating purposes, which would require reinforcement of the electricity grid
- The electricity price from CHP plant is less sensitive to variations in gas price than electricity-only plant. If the gas price goes up, then so does the value of the heat output.

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- Reducing the heat lost at cooling towers will conserve valuable water resources
- Medium to large-scale CHP schemes equipped with heat storage could act as flexible generation plant to complement variable renewable energy sources such as wind or tidal power.
- Distributed small-scale CHP could act as local emergency back-up generation in the event of grid failure. The economic benefits of this could be considerable.

If a programme of new nuclear power stations is being considered, it is essential that the potential for alternatives are evaluated on the same financial basis, i.e. low discount rates and long project lifetimes.

It is essential that the potential for UK CHP is properly reported in UK government publications and that the carbon savings are properly calculated, both in relation to replacing the existing generation and heating system mix and in making comparisons with alternative technologies.

As a rough guide, investment in 1000 MWe of nuclear plant will have the same carbon savings as 2800 MWe of gas-fired CHP plant.

New heat distribution grids will need to be built up within cities with high-density heat loads. This should be considered as a major new piece of national infrastructure similar to the development of the National Grid in the 1920s or the natural gas grid since the 1970s.

It is disappointing that having set a target of 10,000 MWe of CHP by 2010, the government is prepared to lamely report that 'it will not be met'. CHP needs to be seriously promoted.

One way to do this is through the planning process insisting that all new building developments and major urban regeneration projects use CHP wherever possible.

A second way is to encourage the development of small-scale CHP generation. Currently plants under about 500 kW have no access to the market and are being offered low export prices. This has the effect of encouraging the undersizing of plant. The export of electricity should be encouraged. One way that has been suggested is a 'CHP Obligation' (analogous to the 'Renewable Obligation'). A preferable and possibly more cost-effective way would be to offer firm guaranteed export prices including a capacity credit element, as was done under the 1983 Energy Act. This would be analogous to 'Renewable Energy Feed-in Tariff (REFIT)' schemes operating in other European countries.

In conclusion, policies needed to harness carbon savings through CHP include:

- Promoting CHP at all scales, with a long-term progression to big-city CHP.
- Planning policies to develop heat grids in all UK cities and large towns. This is 'infrastructure for the future'.
- Achieving the government's target of 10 GW CHP target by 2010 that has already been set. Even now this could be achieved by encouraging a number of key industrial CHP projects.
- Setting an additional target of 20 GW for 2020.
- Giving support for small-scale CHP, particularly that under 500 kW, either with a 'CHP obligation' or preferably a 'guaranteed feed-in tariff' (as was put in place in the 1983 Energy Act and removed at Electricity Privatisation)
- Promoting domestic micro-CHP in suburban areas beyond the economic reach of heat grids
- If the nuclear option is being considered, then it is essential that the same financial criteria of low interest rates and long project lifetimes (of 40 years or more) are also applied to the alternatives

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4. Responses to DTI Energy Review Questions

Q.1. What more could the government do on the demand or supply side for energy to ensure that the UK's long-term goal of reducing carbon emissions is met?

(a) Actively promote all forms of CHP with a progression to big-city CHP. Put into place steps towards the creation of an urban heat distribution infrastructure. The current UK target of 10,000 MW of CHP by 2010 should be adhered to. Even now it could be achieved by encouraging key industrial CHP projects. A further target of 20,000 MW by 2020 should put in place.

(b) There needs to be particular encouragement for small-CHP operators under 500 kW, who are effectively outside the Electricity Market. There should either be a 'CHP obligation' analogous to the 'Renewables Obligation', or they should be offered firm export prices in a manner analogous to the Feed-In Tariffs available in other European countries.

(c) Actively encourage the growth of the offshore wind industry during its initial start-up phase, by such measures as enhanced capital grants or through additional support for offshore wind, alongside other marine technologies, under the Renewables Obligation.

Q.2. With the UK becoming a net energy importer and with big investments to be made over the next twenty years in generating capacity and networks, what further steps, if any, should the government take to develop our market framework for delivering reliable energy supplies? In particular, we invite views on the implications of increased dependence on gas imports.

An increasing dependence on imported gas requires steps not only to reduce the total volume of gas imports but especially to reduce peak winter demand and the need for LNG storage. This can be done by programmes of CHP (and building insulation). The economics of these should be assessed on winter gas prices rather than annual average ones.

Q.3. The Energy White Paper left open the option of nuclear new build. Are there particular considerations that should apply to nuclear as the government reexamines the issues bearing on new build, including long-term liabilities and waste management? If so, what are these, and how should the government address them?

The acceptance of a nuclear option may require a redefinition of what are acceptable financial criteria for the evaluation of all projects. In order to be considered cost-effective nuclear power requires low interest rates and long project times scales of perhaps 40 years. It is essential that these criteria are recognised and they should also be used in evaluating competing technologies such as large-scale CHP or large-scale offshore wind energy.

Q.4. Are there particular considerations that should apply to carbon abatement and other low-carbon technologies?

If large coal-fired power plants are to be developed with carbon sequestration, it essential that they be sited in locations where there waste heat can be usefully used. Also they should be designed to have flexible operating characteristics to be complementary to variable renewable electricity sources such as wind.

There needs to be research into medium-distance (10 km) heat transmission to make use heat from existing coal and gas-fired power stations and to allow sensitive siting of new energy from waste plants. There also needs to be research into long-distance (50 km) heat transmission so that in the future waste heat from any new nuclear power stations can be used for district heating. It makes no sense to propose new nuclear plants only to throw over half the waste heat they produce into the sea.

Q.5 What further steps should be taken towards meeting the government's goals for ensuring that every home is adequately and affordably heated?

The marginal cost of waste heat from CHP plant, and particularly large plant, can be very low. The promotion of community heating and CHP in inner city areas starting with small-scale CHP plant is likely to provide a cheaper solution to affordable heating in existing homes than some alternative retrofit insulation. It is also likely to be a cheaper option than electric resistance heating in new homes.

Comments are also invited on the following issues, as described in the text:

i. The long term potential of energy efficiency measures in the transport, residential, business and public sectors, and how best to achieve that potential;

A long term goal to make use of 50% of the waste heat from the UK's electricity industry could save at least 10% of the nation's CO₂ emissions.

ii. Implications in the medium and long term for the transmission and distribution networks of significant new build in gas and electricity generation infrastructure;

In the medium term (over the next decade) there will be a need to construct a large number of new LNG storage facilities. There are concerns that these could be terrorist targets. A programme of CHP (and building insulation) will reduce peak winter gas demand and the need for storage. It should be given some economic credit in any evaluations for this benefit.

Also it is conspicuous that this question makes no mention of a heat infrastructure. The development of heat grids will open the way to using new sources of heat, allow the development of a market in heat. Distributed CHP generation and the use of waste heat instead of electric resistance heating will reduce the need for reinforcement of the electricity grid.

The Government should also give serious consideration to setting up a public-private partnership to finance the construction of new offshore electricity networks that will be required to connect offshore wind and other marine renewables into the national grid.

iii. Opportunities for more joint working with other countries on our energy policy goals;

CHP, community heating and wind energy are well developed in Denmark and Germany. We should learn from these countries both as regards technology and implementation policy. We could learn a great deal from Denmark about dealing with high levels of wind penetration on the grid.

iv. Potential measures to help bring forward technologies to replace fossil fuels in transport and heat generation in the medium and long term.

CHP using biomass, increased amounts of energy from waste, coal with sequestration and even nuclear power are all possibilities for the future. It is essential that urban heat grids are established to allow for all of these and provide for fuel flexibility in the future. It is extremely unlikely that this will happen by 'market forces' alone.