RENEWABLE ENERGY TECHNOLOGIES FOR ELECTRICITY GENERATION

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INTRODUCTION

In general, most of the electricity supplied to national transmission grids is generated from either non-renewable sources (coal, oil, nuclear etc.) or hydroelectric dams. These technologies have the advantage that their output is "firm" (i.e. it can be predicted with a high degree of reliability). This characteristic facilitates their integration within a transmission grid, by reducing the amount of reserve supply capacity to that required to cover any unexpected outages of generating plant.

The output of electricity supplied by some renewable sources cannot be so easily predicted in advance because of their dependence on naturally varying phenomena (e.g. wind or sunshine). To accommodate this variability within the grid, additional amounts of conventional plant might have to be maintained in reserve, which would add to the overall system costs. This paper will examine some aspects of renewable energy technologies for electricity generation as well as factors to be considered in the incorporation of renewables within a grid.

It is difficult to generalise about the implications of renewables for electricity supply, because of the importance of grid characteristics, the types of plant on the system and the geographic variables. Therefore this paper will concentrate on the role of renewables in the electricity supply industry (ESI) in the UK. After first describing the new structure of the ESI and its pricing policy, the manner in which renewables have been treated by this structure will be described. Other recent important developments for renewables in the UK will then be summarised before concluding with some discussion on some wider aspects of renewables.

THE UK ELECTRICITY INDUSTRY

The previously nationalised ESI in the UK was privatised in 1990/91 as part of a process to encourage greater competition in the electricity generation and supply business. The main components of the industry in England and Wales and their interaction are outlined in Figure 1[1]. There are three main aspects of the ESI.

Generation. Two privatised companies (National Power and PowerGen) control nearly all non-nuclear generation, whilst the nuclear stations (together with some gas turbine and hydro plant) are retained by the state-owned Nuclear Electric.

Transmission. The electricity generated above is supplied to the national grid, which is operated by the National Grid Company (NGC). This transmits the energy from the power stations to the main centres of demand.

Distribution. The supply of electricity to customers is carried out through local distribution networks, which are operated by 12 regionally-based, privatised Regional Electricity Companies (RECs). These companies also effectively own the NGC although restrictions have been put in place to ensure the operational independence of the NGC. Customers with demands below a certain amount have to purchase their electricity from their local distribution company, whereas large consumers can enter into agreement with other distribution companies or authorised suppliers.

This structure is an evolving one.

- By 1998 any customer will be free to purchase electricity from any part of the ESI, with his local distribution company receiving only a "use of system charge".

- Anyone is free to operate a power station provided they have a license (or qualify for an exemption). This has led to several companies (including several RECs) starting to build their own generating capacity (primarily combined-cycle gas turbines) in the past few years.

- The transmission and distribution companies form a natural monopoly and so, in order to prevent abuse of their status, the charges for use of these system are limited to a "RPI-X" formula, where RPI is the retail price index and X is a formula, whose value can be changed but which is initially zero.

The ESI in Scotland is different owing to its vertically integrated historical nature. Here there are two privatised companies (Scottish Power and Hydro-Electric) and the public sector Scottish Nuclear.

THE ELECTRICITY MARKET

The mechanism adopted to encourage greater competition amongst electricity generators is the "pool" (see Figure 1). Generators sell electricity through a wholesale market (the pool) from which suppliers can buy the electricity for onward sale to individual customers. The pool is operated by the NGC and operates as follows.

- At a specific time each day, the generators tell the NGC how much electricity they are prepared to provide from each of their units for the following day. These bids are for 30 minutes periods throughout the day and also include the price required for supply during each period.
- The NGC estimates the supply required throughout the next day.
- The NGC then ranks the bids in each 30 minute period by price to provide a merit order from which schedules the stations required to operate the next day in order to fulfil the required supply in each period. Failure of a generator to fulfil his promised quota incurs a penalty.

This system also takes into account constraints imposed by the transmission system (e.g. the demand in the south of England exceeds the local supply), plant characteristics (e.g. the time required to bring a new station on stream) and system stability (e.g. the need to provide reactive power and ensure sufficient reserves to cover unforeseen plant outages).

The price offered by the NGC for electricity generation varies throughout the day as shown in Figure 2. All generators providing electricity in each period are offered the same system marginal price or SMP (i.e. the price offered to the most expensive generator in each period) plus an additional factor known as the capacity credit. This factor also varies from period to period and is calculated as:

Capacity Credit = Loss of Load Probability x (Value of Lost Load - SMP)

The Value of Lost Load is a measure of the additional price that pool customers are prepared to pay to avoid loss of supply. It originally was set at £2/kWh but will vary with the generating capacity of the system. The Loss of Load Probability will vary throughout the day as the ratio of demand to capacity varies (see Figure 2). As such it is the mechanism which is intended to ensure that there is always an incentive to build sufficient new generating plant to meet peak demand.

The total amount paid to generators (the SMP + capacity credit) is known as the pool input price (PIP). The amount paid by suppliers also varies with each 30 minute period and is known as the pool output price (POP). This is calculated as

$$\text{POP} = \text{PIP} + \text{uplift}$$

where the uplift covers such factors as errors in demand forecasting, maintaining reserve, services, etc.

This mechanism ensures that generating plant are subject to market forces and that, in time, this should ensure the lowest costs of electricity generation. (In practice the generators and distribution companies have entered into contracts to avoid complete dependence on the variability of the pool thereby stabilising prices somewhat.)

THE NON-FOSSIL FUEL OBLIGATION

Outline of the System

In the period before privatisation it was anticipated that, in the short term, the electricity generated from renewable sources was likely to be more expensive that from fossil-fuelled stations. Therefore the Government obliged the RECs to purchase a certain amount of electricity from non-fossil fuel stations (i.e. nuclear and renewables). This Non-Fossil Fuel Obligation (NFFO) is placed on each of the RECs and is co-ordinated through the Non-Fossil Purchasing Agency (NFPA), which is an agent of the RECs. It is funded by a levy on all electricity suppliers as a proportion of their sales of leviable (fossil fuel generated) electricity. This proportion was set at 11% for 1991/92.

The proceeds of the levy are paid to RECs by the NFPA to make up the difference between the pool price and the contractual price for generators who qualify under the NFFO. The clearance for such a system was given by the European Commission until 1998, so contracts under the NFFO last only until that time. (The possible extension of the NFFO is likely to be discussed before 1998).

Implications for Renewables

The NFFO is widely perceived as a mechanism for establishing a market for renewable energy systems to allow them to compete with older, more established generating technologies. A certain size of market is required to generate developments in technology, provide economies of scale in manufacturing and give confidence for new industries to enter the market. To date, this obligation has been applied in two tranches for renewable technologies (as well as one tranche of about 8 GW for nuclear). The first order in 1990 involved a total contracted capacity of 150 MW from 75 projects. The second order in 1991 covered contracts for 472 MW from 122 contracts as summarised in Table 1.

Table 1 Summary of the Second Round of NFFO Contracts in England and Wales

Technology/ Energy Source	Number of Contracts	Size of Obligation (MW)	Contract Price (p/kWh)	Size of Contracts (MW)
Landfill Gas	23	48.0	5.7	0.4 -5.0
Sewage Gas	19	26.9	5.9	0.3 - 7.8
Municipal & General Industrial Waste	10	261.5	6.6	4.1 - 103
Hydroelectricity	12	10.4	6.0	0.02 - 0.6
Wind	49	82.4	11.0	0.1 - 7.4
Other Waste Combustion	4	28.2	5.9	1.0 - 12.5

A recent report to the UK Department of Trade and Industry by the Renewable Energy Advisory Group (REAG) [2] recommended that further tranches be implemented to take the total capacity for new renewables to 1,500 MW by the year 2000. This is currently under consideration by the UK Government.

Assessment of Renewables under NFFO

To qualify under the NFFO scheme, a generator had to be able to assure the regulatory authorities (the Office of Electricity Regulation or OFFER) that the plant is fuelled or driven other than by fossil fuel. In addition the plant must satisfy a "will secure" criterion, which includes (amongst other factors):

- Availability of a defined site with planning permission or good prospects thereof;
- Technical viability of the scheme and realistic achievements of its projected output;
- Economic viability of the scheme (e.g. justified capital and operational costs, ability to meet the contracted commissioning date);
- Satisfactory prospects for all wayleaves and consents (e.g. electrical connection to the site).

Having satisfied these criteria, generators were invited to submit final bids for the price below which they would not be contracted to supply electricity for the duration of the contract (i.e. until 1998). In the 1991 tranche, the bid prices for individual technologies were ranked by the NFPA without regard to factors such as availability or electrical losses. Quotas were set for the total capacity supplied by each renewable technology (see column 3 of Table 1). Within each technology a single price was paid to all generators, which was high enough to ensure that the capacity quota was met (see column 4 of Table 1). Hence different technologies received different prices and the more efficient generators within each technology (i.e. those with the lower bid prices) are rewarded more compared to those which offered near the marginal bid price.

Treatment of Intermittency of Renewables

In assessing the bid price, consideration is given to the intermittent nature of the supply from some renewables. The largest amount of electricity supply for which a contractor can bid is the maximum generator output less the electricity used on site. This amount is framed in terms of Declared Net capacity (DNC). The Secretary of State has regulated on how to determine the DNC for intermittent renewables in order to equate this with the equivalent capacity of base load plant that would produce the same average energy output [3]. The DNC is defined as:

$$DNC = A \times B$$

where A is the highest generation of electricity which, if available uninterruptedly, could be maintained indefinitely without causing damage (less that consumed by the plant) and B is given by the following table.

Table 2 Factors Used in the Definition of DNC

Description of Station	Value of B
Station driven by tidal or wave power	0.33
Station driven by any form of water power other than wave or tidal	1.00
Station driven by wind power	0.43
Station driven by solar power	0.17

OTHER RECENT UK DEVELOPMENTS ON RENEWABLES

As mentioned earlier, the REAG has recently submitted a report [2] reviewing the UK Government's strategy "to stimulate the development and application of renewable energy technologies, wherever they have the prospects of economic viability and environmental acceptability". This report concluded that the point at which various renewables would become economic was dependent on many factors (oil prices, costing policies, cleaning up emissions from fossil fuel combustion, etc.), whose uncertainties made it impossible to forecast accurately the future market share of individual renewable technologies. The theoretical accessible potential was calculated to be enormous (see Figure 3) though this would be limited by economic considerations (Figures 4 and 5). A plausible figure of what would be feasible by 2025 was considered to be about 60 TWh/y corresponding to about 20% of UK demand in 1991. This would result in savings of about 40 million tonnes of carbon dioxide emissions annually. Much of this target could be achieved using technologies such as energy crops and utilisation of wastes which would probably not be deemed to be intermittent in the sense adopted in Table 2.

A wide ranging appraisal of research, development, demonstration and dissemination of energy technology within the UK is currently underway [4]. This will consider (among other factors) the range of energy technologies (both supply and demand side), their future prospects for deployment in the UK up to 2025 and their environmental impact. It will include renewables and will model their potential contribution in each of a range of different future scenarios, including those of low and high oil prices as well as heightened environmental concern. This modelling will be carried out utilising the Market Allocation module MARKAL, which was developed by the IEA. The results are likely to be published in 1993.

SOME ASPECTS OF THE ELECTRICAL INTEGRATION OF RENEWABLES

As stated in the Introduction, it is difficult to make generalised statements concerning the integration of intermittent renewable electrical generation because of the dependence on the characteristics of the grid and other plant. Some renewables can be highly predictable (e.g. tidal stations), whilst other would have firmness of supply similar to or better than fossil-fuelled stations (e.g. waste incineration and large-scale hydroelectric schemes). In a fully operational pool as described earlier, firmness is a measure of how well a generator can predict the amount of electricity that can be supplied for the following day. In the UK predictions of the supply of electricity from some renewables (such as wind energy) would be subject to uncertainty on this time scale.

To a first approximation [5], the firm capacity of small penetrations of wind power into a grid can be treated as similar to that of conventional plant (see the Appendix). An analysis of a theoretical UK [6] grid has predicted that the firm power supplied by a tranche of wind turbines with an annual output of a nuclear station was almost equal to the average output of the turbines. This confirms the results of the simple analysis that there is no significant penalty for small levels of penetration (a few percent) of wind turbine generation onto the UK grid. However this value might not apply to other grid systems, with a different mix of conventional plant (especially those with large amount of capacity with poor load following capabilities).

CONCLUSIONS

A market mechanism has been set up in the UK which, when fully operative, will make the costs of electricity generation from different sources fully transparent.

In order to stimulate the development and application of those renewable energy technologies which have prospects of economic viability and environmental acceptability, a Non-Fossil Fuel Obligation operates in the UK until (at the moment) 1998. This scheme allows the payment of premium prices to generators using renewable energy sources for that period by imposing a levy on the sale of electricity from fossil fuel powered stations.

The assessment of renewable generation to date takes little or no account of the influence of intermittent sources on the grid (other than the cost of connection, where applicable). Analyses of a small percentage of intermittent wind energy on the UK grid have shown that its firm capacity is close to its average annual output, thereby justifying this simplification.

REFERENCES

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APPENDIX

SIMPLE STATISTICAL ASSESSMENT OF THE FIRM CAPACITY OF WIND TURBINES [6]

This arguement follows that presented in Reference 7. Initially a system comprising conventional generating capacity is assumed to have a probability P(W) of being able to generate power W at any time. A small additional capacity from wind turbines of X is then added to the system. This additional capacity is assume to be available for a fraction of the time T (and therefore unavailable for 1-T). If X is small compared to W, then the probability of the system comprising conventional capacity and wind turbines being able to generate power W is given by

$$(1-T)\times P(W)+T\times P(W-X)$$

Expanding this second term as a Taylor series yields

$$(1-T)\times P(W)+T\times\left[P(W)-X\times P'(W)\right]+\text{ higher order terms}$$

This series can be simplified to

$$P(W)-T\times X\times P'(W)+\text{ higher order terms}$$

This is a Taylor series for

$$P(W-T\times X)$$

Therefore, the additional capacity of the wind turbines (X) contributes an equivalent firm capacity of T x X to the system. Since T x X is the average output of the wind turbines, this indicates that the firm capacity of wind power is equal to its average power.

FIGURE 1 THE STRUCTURE OF THE ELECTRICITY INDUSTRY IN ENGLAND AND WALES

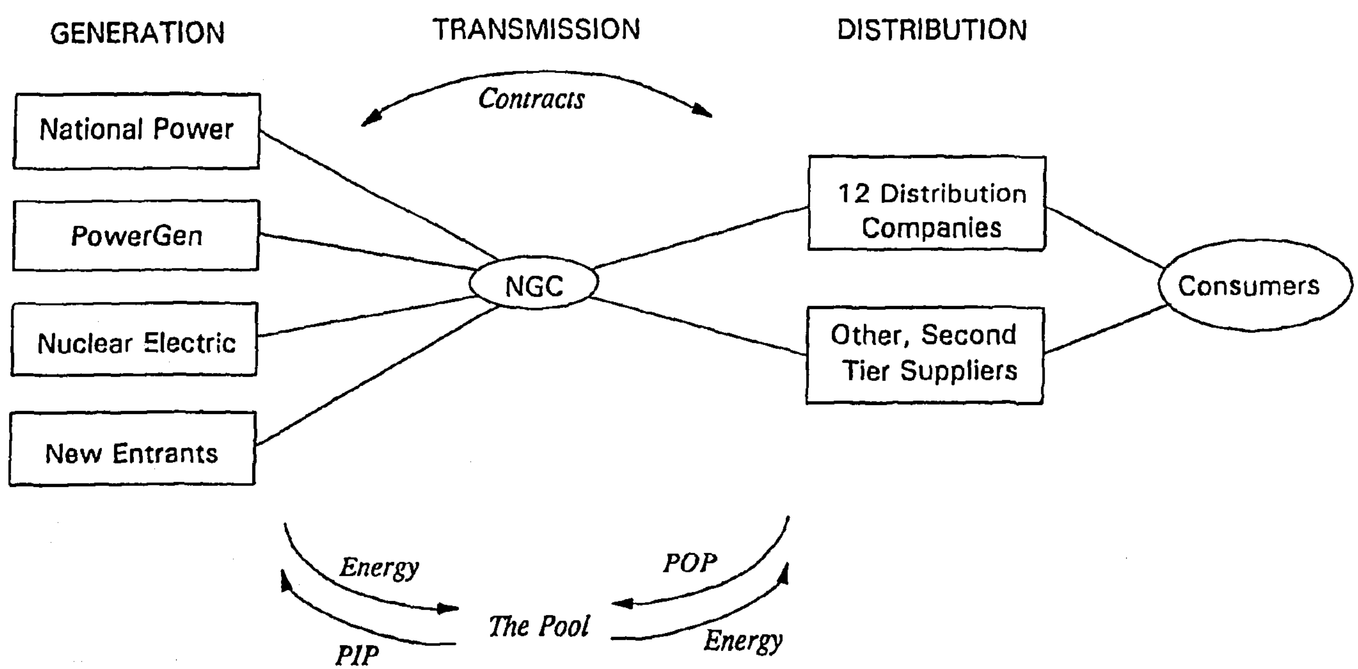


FIGURE 2 ILLUSTRATION OF POOL PRICE CHANGES

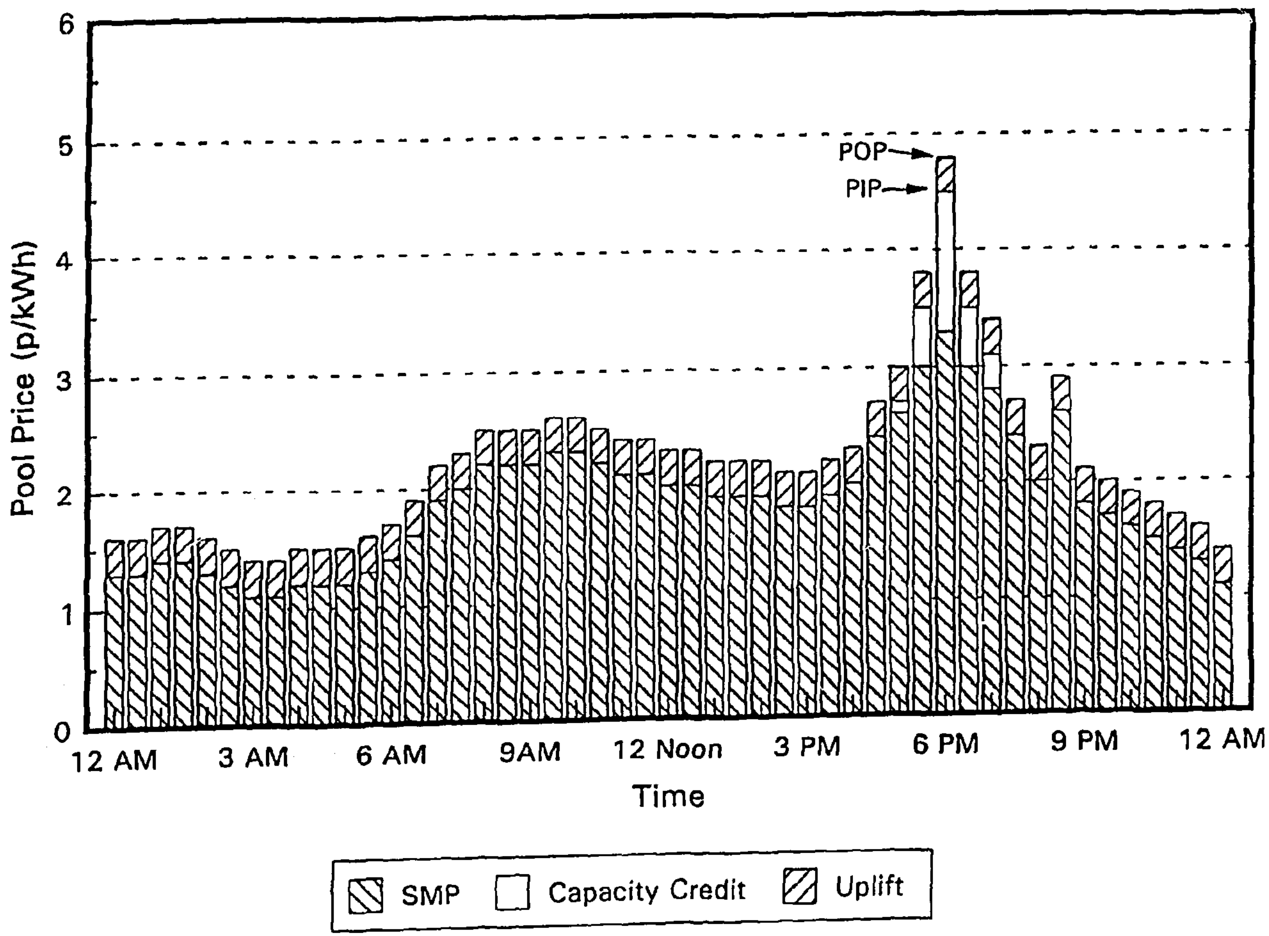
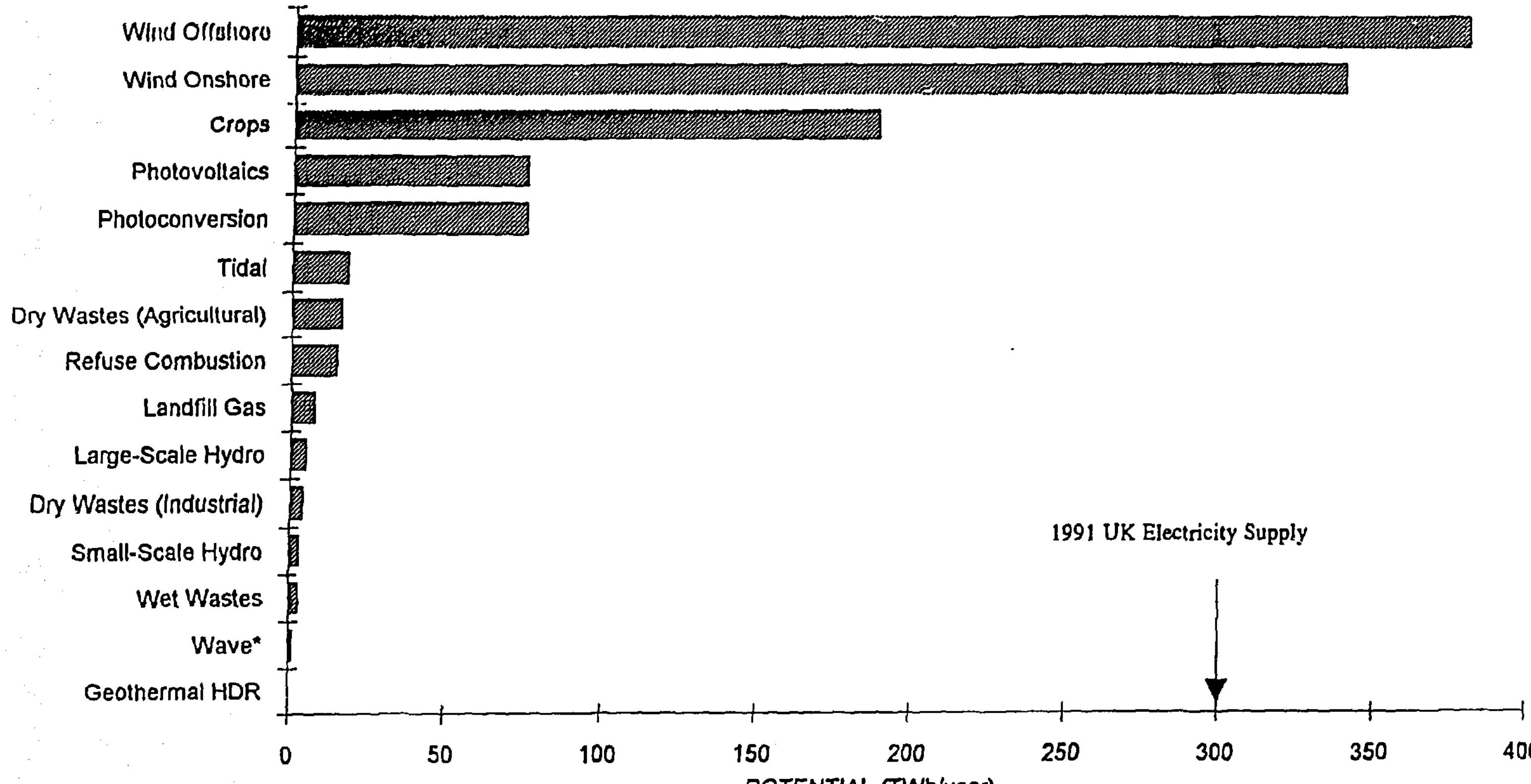


FIGURE 3 ACCESSIBLE POTENTIAL OF ELECTRICITY PRODUCING TECHNOLOGIES AT LESS THAN 10 p/kWh (1991) AT 8% DISCOUNT RATE



* The wave energy figure is based on provisional data