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A STUDY OF ELECTRICITY STORAGE AND CENTRAL ELECTRICITY GENERATION

D G INFIELD

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A STUDY OF ELECTRICITY STORAGE

AND

CENTRAL ELECTRICITY GENERATION

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ABSTRACT

A systems approach has been adopted for the evaluation of energy storage for large scale electricity generation. Fuel cost savings derived from the various functions of electricity storage have been estimated. Other advantages attributable to storage such as capacity credit and increased security of supply have not been dealt with in this analysis.

The fuel cost savings associated with central electricity storage are usefully broken down into the following categories; immediate reserve, reserve to cover scheduling and dispatching error, and load-levelling (including the more restricted case of peak lopping).

In contrast with previously published work, this study indicates that fuel cost savings due to load-levelling arising from an improved operating regime for plant (in practise a reduction in hot starts and standby use of plant), are most important and outweigh the advantages gained in system performance from shifting load to plant of higher efficiency. In some instances the inefficiencies of the storage device exceed gains from merit order shifting.

Annual fuel cost savings of about £M42 per annum (1981 terms) for a plant such as Dinorwig are indicated by the analysis.

A simple economic analysis suggests that increased amounts of storage should be installed on the CEGB system, perhaps up to 4 GW at 1981 fuel prices. Real fuel inflation might justify even higher penetrations. The optimum storage capactiy (GWh) for different penetrations is also evaluated.

Lastly an analysis of savings resulting from a reduction in transmission and distribution losses provided by distributed storage is presented. Results show that high storage efficiencies are required to realise significant savings. With this proviso, up to about £M10 per annum (in 1981 terms) could be saved.

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ACKNOWLEDGEMENTS

This work would not have been possible without the generous assistance of ERSU colleagues. In particular, J A Halliday in organising the computing and E A Bossanyi for advice in application of the Reading/RAL computer model. I am grateful to F M Russell for posing the problem and his criticism of the original draft of this report. Thanks also to N Jenkins for providing the necessary expertise in electrical engineering.

1 Background to the study

The study presented here arose from a desire to quantify the benefits attached to the application of storage to large scale electricity generation.

It was decided to restrict the study to the UK and in particular to the Central Electricity Generating Board (CEGB) system. Limitations on time and resources have meant that it has not been possible to use analysis techniques of the complexity and sophistication used by the CEGB and the Electricity Council. Instead simple methodologies have been developed which are considered to give reasonable estimates of the important factors. In addition extensive use has been made of the computer model of large scale electric generation initially developed at Reading University by G E Whittle[1,2,3] and since then significantly improved by E A Bossanyi and J A Halliday of the Rutherford Appleton Laboratory.[4,5,6]

It is worth pointing out that the work is not merely duplication of CEGB analysis for as such it would be of very limited value. Different insights are gained from the application of alternative analytical approaches, and, perhaps more importantly, the wider viewpoint of SERC enables different questions to be asked. Specifically this means that the impact of storage on the complete system (including generation, transmission, distribution and end use) can be contemplated in contrast to the narrower confines of the CEGB analysis (primarily concerned with the generation and transmission of electricity). Moreover, as research developed, it was realised that the impact of storage based on the consumer's premises and load management could also be included within the framework of the analysis.

Further motivation for this study stems from the number of storage technologies presently awaiting further development. These include underground pumped hydro, compressed-air storage, large-scale thermal energy stores, advanced batteries, flywheels, kinetic ring energy storage and superconducting magnetic energy storage.

The requirement for storage in generation systems containing a significant renewable component (eg wind or wave powered electricity generation) has not been assessed in this study. A number of case studies dealing with these issues exist but the results are inconclusive.[7,8,9]

The crucial question of whether the roles that storage can play (such as peak lopping and spinning reserve) are better provided in a conventional manner applies independently of the existence of renewables on the system. Their effect can be viewed simply as an increase in the uncertainty in demand to be met by the remainder of the system.

Electricity storage could provide significant running cost savings for utilities such as the CEGB. To date, however insufficient analysis exists of the system aspects of such technology to enable well founded decisions to be made regarding future storage deployment. It is hoped that this report goes someway towards providing this with respect to the fuel cost savings attributable to storage in a central electricity supply system.

2 The role of energy storage in central electricity supply systems

For the purposes of this study electricity storage will be taken in general to mean energy storage which can be readily converted both to and from electricity. We will not be concerned with the technical aspects of the storage device except in so far as they impinge on the operation of the complete system. In other words characteristics such as efficiency and response time are directly relevant but the complex way in which these depend on the physical processes involved are of peripheral interest.

The benefits attributable to electricity storage depend critically on the characteristics of the particular storage medium considered. It is convenient to categorise storage as either centralised (as with large pumped storage installations such as Dinorwig) or distributed (as for example in the case of battery banks or small flywheel systems, which can be located within the distribution network or even on consumer's premises). Further subdivision, into categories of rapid response (ie able to move from zero to full load in about 11 seconds or less) and others, is also helpful.

Electricity storage can be used in place of gas turbines or conventional thermal plant for peak lopping in merit order by which we mean the meeting of peak demands. As such it can provide fuel cost savings and be viewed as additional capacity. At present, however, the CEGB has a notable overcapacity and in this situation it would be inappropriate to attribute storage with a capacity credit.

Storage plant may also be used for load-levelling by charging during periods of low demand (for example overnight) and discharging at times of high demand (during afternoon and early evening). The charge/discharge cycle is most likely to be daily to smooth diurnal variations in load, but weekly smoothing may also be considered. Such an application of storage is related to merit order generation and its value is crucially dependent on the round trip storage efficiency. In addition this approach to storage utilisation has the advantage of reducing the two-shifting and load following of large conventional generating units.

Rapid response storage has the further advantage of being used to provide immediate reserve capacity (spinning reserve) in the event of a sudden loss of power by the tripping out of large unit or line loss, and frequency control (conventionally supplied by governor action on part loaded thermal plant). The latter role reduces the need for governor action and thereby improves the performance of conventional plant. Immediate reserve can also be provided during periods when the storage is being charged, by instantaneous cessation of charging. Some forms of storage such as pumped hydro can also be used to provide synchronous reactive compensation when free-running.

Storage may also be used to respond to unexpected variations in demand (scheduling error) and dispatching error where it would substitute for steam reserve and gas turbine operation.

All the above comments apply to both centralised and distributed storage. The latter, however, gives rise to additional benefits. Locating storage units close to load centres may give transmission and distribution savings through an increase in the load factor, although the extent to which savings can be realised depends on the storage efficiency and on how far down the transmission or distribution network the storage can realistically be placed. Savings can arise both from an actual reduction in transmission and distribution losses and from the postponement of transmission and distribution reinforcement giving rise in effect to a capacity credit element. In some instances distributed storage may also result in an increased security of supply.

Although our primary concern is with electricity storage, as defined in the opening paragraph of this section, other forms of storage such as night storage radiators will also give rise to a number of the benefits listed above, ie those arising from a smoothing of the demand profile. Here the connection with load management can be seen clearly because its role is also to smooth the demand profile. Load management and the more recent possible interactive load control are both most successful when the interruption/control of supply does not give rise to adverse effects at the point of electricity use; this will usually be case where the end use application itself entails some intrinsic energy storage.

3 A synopsis of the CEGB position

In the UK, the CEGB have undoubtedly been responsible for more research into electricity storage than any other single organisation. This is hardly surprising since the impact of storage is on the generation and transmission system primarily. On the other hand the impetus behind load control comes mainly from the Area Boards and the Electricity Council who are more concerned with distribution than generation.

Given the CEGB's interest in storage technology and the fact that they are also responsible for the planning and operation of large scale centralised storage, it was considered appropriate to include a very brief summary of their research and a statement of their current position.

In 1975 a report published by the Central Electricity Research Laboratory (CERL) [10] estimated the cost of providing 'spinning reserve' on the CEGB network at about £4M in 1973, rising to about £15M in the 1980's. It was anticipated that Dinorwig, then planned, would provide for this particular need for a number of years. The report also pointed to the advantages of load smoothing, leading to reduced load-cycling on power stations and the consequent improvement in reliability and reduced maintenance. These benefits were not quantified but it was emphasized that they would be most important when the proportion of nuclear plant had grown to a point where it would need to load-cycle with a number of attendent problems.

Savings due to load-levelling were also thought to be significant when the nuclear component had grown to exceed night-time demand. With the then current amount of nuclear plant little benefit was expected from this mode of operation. Annual fuel cost savings of between £1/kW pa and £2/kW pa (presumably in 1975 terms) were calculated for 1985 depending on the storage efficiency and rate of increase in the cost of oil. Savings after this time were shown to be highly dependent on the rate of growth of nuclear power. Different storage technologies were reviewed with the conclusion that, subject to the nuclear programme developing as planned, storage could be widely employed on the CEGB system during the 1990's. Thermal storage, underground pumped hydro, hot sodium in conjunction with fast reactors and some forms of batteries were considered to be sufficiently promising to justify further research work. Flywheels, conventional compressed air and electromagnetic storage were found to be unattractive for application on the CEGB system.

Batteries for bulk energy storage were dealt with in greater detail in another CERL report.[11] It was concluded, following Garder[12] that the best location for such battery systems would be on the 11 or 33kV circuits of the distribution system. The additional savings arising from distribution of the storage in terms of cost saving on transmission were estimated at about £2/kW output pa. Again it was concluded that electrochemical batteries could in principle give economic benefit but only when the nuclear component exceeded that required to meet the base load demand.

More recently Talbot[13] has re-examined the case for electrochemical batteries on the CEGB system in the light of developments in both battery and solid state inverter technology. Storage in excess of the pumped storage then existing or planned was not considered viable until after the end of the century and was once again dependent on the expansion of nuclear generation. By 2025 AD, with a then expected 100 GW of nuclear plant (in a total of about 150 GW)[14], an application for approximately 12 GW of storage was expected. The distribution savings for batteries at 33/11 kV substations in contrast to direct connection to the 400 kV network were updated to £6/kW pa for an average installation (1981 costs).

Overall, advanced batteries Na/S and Zn/Cl_2 showed the greatest economic potential for load-levelling when compared with generation from fossil fuelled plant (assuming nuclear base-load). Advanced batteries also appeared promising as a replacement for gas turbines in peak lopping (on the assumption that pumped storage had already replaced gas turbines for this duty, as far as was economically viable). The basis of the analysis of storage allocation to cover scheduling and dispatching errors was taken from the work of Farmer.[15]

The review paper 'Large-scale electrical energy storage'[16] confirms broadly the views summarised above. It argues that the differential fuel cost between day and night generation is presently too small to overcome the inefficiency of available storage, and will remain so until a large nuclear component has been developed. On the assumption that the load profile does not change significantly and a suitably large nuclear component exists it is estimated that storage amounting to 15% of total capacity could be used to smooth diurnal load variations, and 20% if weekly smoothing is considered.

4 Analysis of storage primarily based on the computer simulation of a large central electricity generating system

4.1 Introduction to modelling techniques

Central electricity generation systems are frequently studied using probabilistic techniques[15] and in particular probabilistic simulation models (eg Monte Carlo simulation)[17,18] in which probability distributions are assigned to various grid system variables (ie loads, scheduling error, plant availability, etc). The system operation can then be assessed statistically in terms of performance parameters such as loss-of-load probability. Although such models require relatively small amounts of computer time they do not take into account time-dependent effects. This causes problems for the modelling of storage, the scheduling of which is time-dependent and thus cannot be easily incorporated into a probabilistic approach.

It is possible to extend such models to include some time-dependent effects, as with the frequency and duration approach[19,20] but to treat these effects fully it is necessary to use a time-step simulation model.[2,3,4,5,6]

The model used in this work is based on a time-step of one hour, ie it uses hourly load data and simulates the operation of the whole grid system hour by hour during the entire simulation period which for our purposes is one year.

Notable disadvantages of this approach are that large amounts of computer time are required, and also that it is difficult to derive any results pertaining to system reliability which depend on events of low probability such as unforeseen failures of large generating sets or line losses.

Nevertheless, the model is useful for an assessment of storage. Detailed estimates of fuel savings can be derived from a year's simulation, along with information about optimum grid control strategies such as the way in which spinning reserve and storage should be scheduled. However, for the reasons outlined above, the role of storage as immediate reserve to cover unexpected outages cannot be handled by the model and a separate analysis is provided. On the other hand the operating regime experienced by generating plant units can be studied. Parameters such as load factors and the numbers of hot and cold starts for steam turbine units are calculated and these will be shown to be significant as regards the operation of storage.

The aggregated or lumped nature of the model is appropriate for central electricity generation and is therefore restricted to large centralised storage units directly connected to the transmission network (or supergrid). No assessment is made of transmission or distribution related factors and consequently these aspects of distributed storage must be dealt with separately. The efficiencies of charge and discharge of storage will be assumed equal, thus the storage will be characterised by a one-way efficiency η (the overall efficiency of the cycle being η^2).

Two important parameters in the model are SR1 - the proportion of predicted demand to be held as spinning reserve on fossil fuelled steam plant, and QSF - the fraction of storage used for load-levelling.* Both parameters take a constant value in each simulation run although it is recognised that in practice the scheduling of storage and spinning reserve on the CEGB grid will be partially in merit. Modelling the continuous assessment of marginal incremental generation costs on different plant and the optimisation of storage scheduling would create unjustified complication within the model and increase computing time inordinately. However, the parameters can be optimised on an annual basis, ie SR1 and QSF are varied until a combination is found which minimises the fossil fuel cost of the simulation run. This two-parameter optimisation was performed using a standard 'simplex' minimisation routine. Not all the results presented have been taken from optimised runs. This is permissible either where SR1 and QSF have been fixed by some external constraint, or where they are insensitive to the variable in question as is the case with T, the characteristic time of the store (defined as storage capacity (GWh)/maximum storage rating (GW)).

A detailed description of the model may be found in Appendix 1. This should not be overlooked since the value of the model depends crucially on the extent to which its assumptions represent reality. Some attempt at validation is also included.

4.2 Case Study

The generation system chosen for study is based on the CEGB plant mix anticipated for 1985;

Coal fired steam plant	:	42.5 GW
Nuclear Plant	:	8.2 GW
Gas Turbine Rating	:	3.5 GW

A more detailed breakdown is included in Appendix 1, but it should be noted that oil fired generation is assumed to be negligible by 1985. Although the nuclear component is far below that which the CEGB believes is necessary to justify further storage, it is now clear that for a number of reasons[21,22] the nuclear programme will not develop at the rate previously hoped for by the CEGB and consequently if storage is to have a role in the medium term future (ie up to 2025) it must be in systems with plant mixes not dissimilar to the one expected for 1985.

Storage penetrations of up to 4 GW (approximately 10% of peak load) and storage capacities of up to 21 GWh have been investigated for a range of storage efficiencies. Standing losses from storage plant have been neglected. In all cases presented here the CEGB hourly electricity demand profile for 1978 has been used as this is thought to be reasonably representative of the demand in 1985 - the year for which the study is aimed. All fuel prices and plant overheads are calculated in March 1981 terms.

*See Appendix 1 for further details.

Figure 1 : Fuel cost savings from large scale electricity storage (T=5.5h)

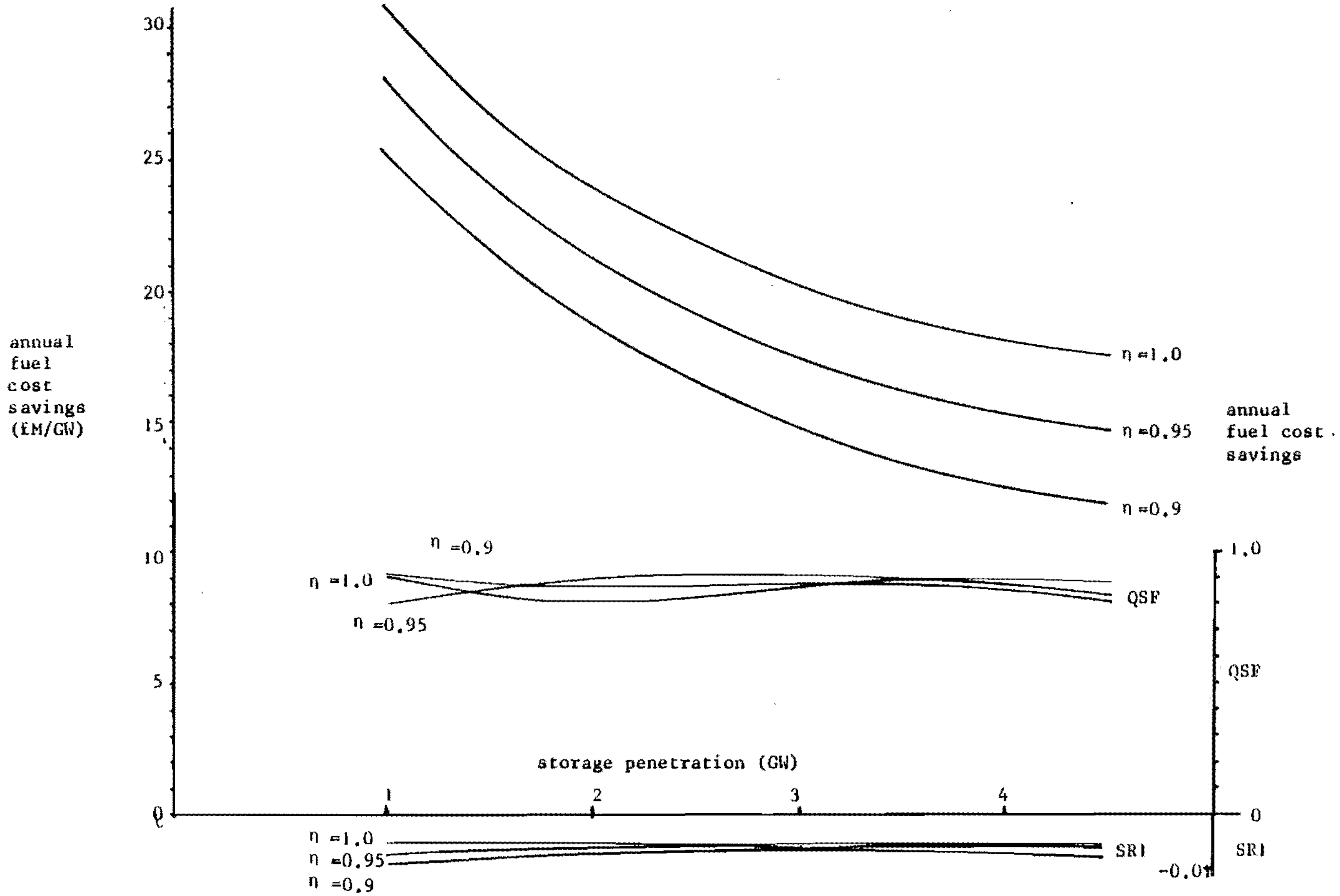


Figure 1 presents the results of a full optimisation for one-way storage efficiencies of 0.90, 0.95 and 1.00. For simplicity T is fixed at 5.5 hours and the variation of annual fuel cost saving with installed storage rating is shown. These are the fuel cost savings to be derived from storage capable of fulfilling all roles described in Section 2 except that of immediate reserve. The values of SR1 and QSF which give optimum fuel cost savings are also shown in the figure. Negative values of SR1 indicate that it is preferable to under-estimate the load slightly and then use storage to make up for any shortfall which may occur, rather than to schedule positive spinning reserve on thermal plant. The high values of QSF suggest that most of the storage capacity should be used for load-levelling. This conclusion appears at odds with CEGB analysis and further results are needed to clarify the issue.

Figure 1 also indicates the expected fall in the marginal value of storage with increasing storage penetration although the rate of fall is clearly dependent on the efficiency of the storage system, higher efficiencies giving rise to smaller reductions in savings.

In order to explain the above mentioned discrepancies with the CEGB analysis it is necessary to break down the savings derived from storage into components dependent on the various different functions that storage may fulfill, as described in Section 2.

By removing all uncertainty in load prediction the model allows savings associated with scheduling and dispatching error (ie a spinning reserve use of storage) to be removed. This leaves savings associated with load-levelling and peak lopping which will not be differentiated in this analysis. (After all peak lopping is really only a restricted application of load-levelling). These savings may be further broken down into savings attached to merit order shifting, ie using more efficient plant in place of sets lower down the merit order, and savings in hot starts and standby operation resulting from the smoothed daily load profile. It is here that our analysis diverges from that published by the CEGB. They correctly point out that the inefficiency of storage is not compensated for by the differential efficiencies of plant in the merit order except on occasions where expensive peaking plant is required. Thus they conclude that only peak lopping is justified. Their published analysis is unable to account properly for the fuel savings stemming from eased operation of the plant, ie the reduction in hot starts and standby operation. In contrast, our modelling approach enables these fuel savings to be obtained in a straightforward manner. Additional benefits of reduced wear and maintenance, further consequences of eased plant operation, have not been included and so, if anything, we have under-estimated the running cost savings due to storage used in this way.

Figure 2 shows the breakdown of fuel savings into these different categories for a 1000 MW storage penetration with 0.90 one-way efficiency as a function of the characteristic time, T of the store. Savings identified with the spinning reserve role of storage (ie total fuel saving minus load-levelling fuel savings) increase with T until some asymptotic value is reached and primarily result from a reduction in gas turbine use (also shown on the figure).

Figure 2 : Breakdown of savings due to storage (1 GW penetration)

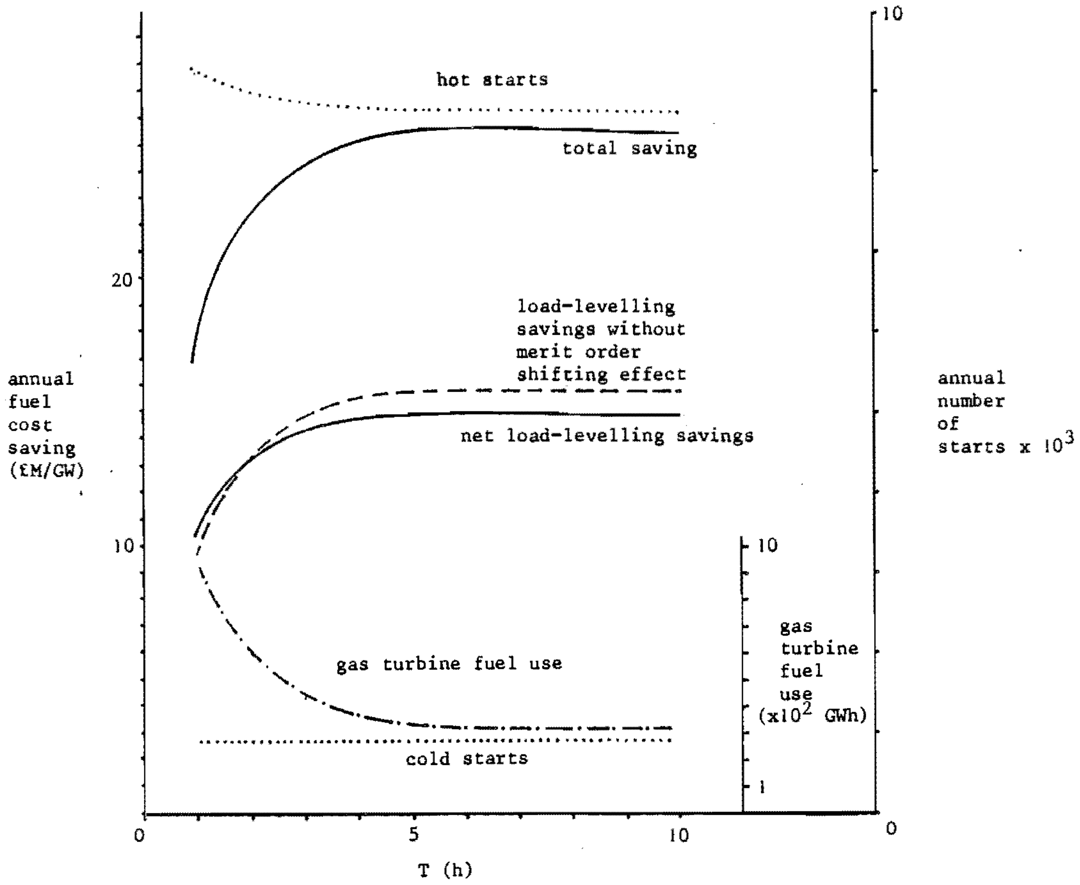


Figure 3 : Breakdown of savings due to storage (2 GW penetration)

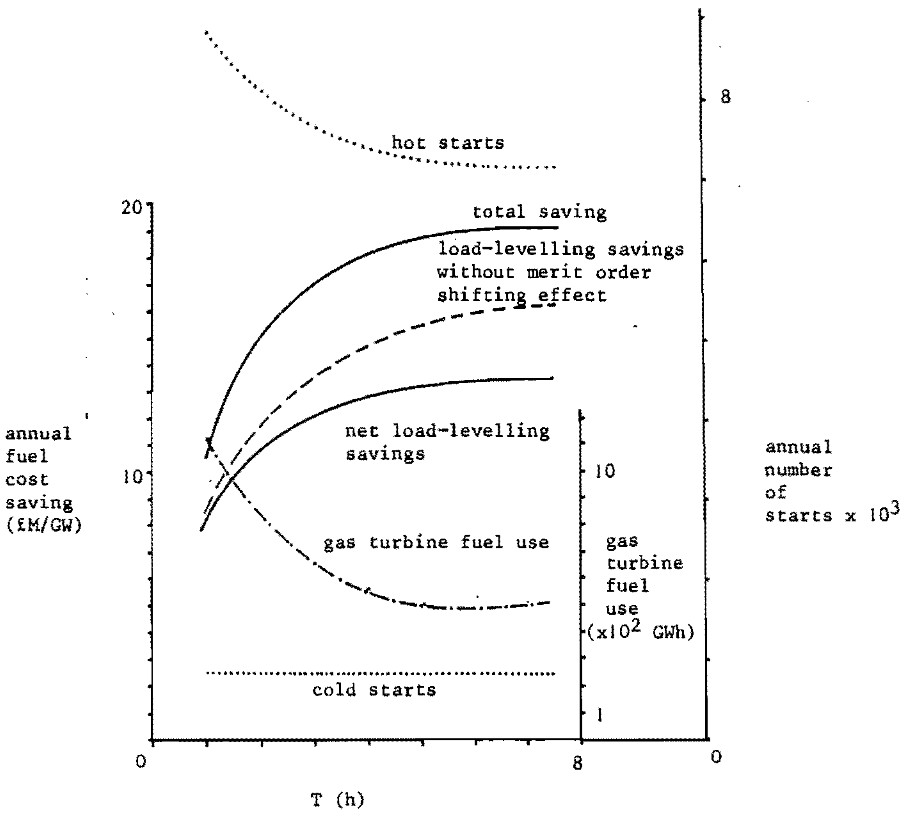
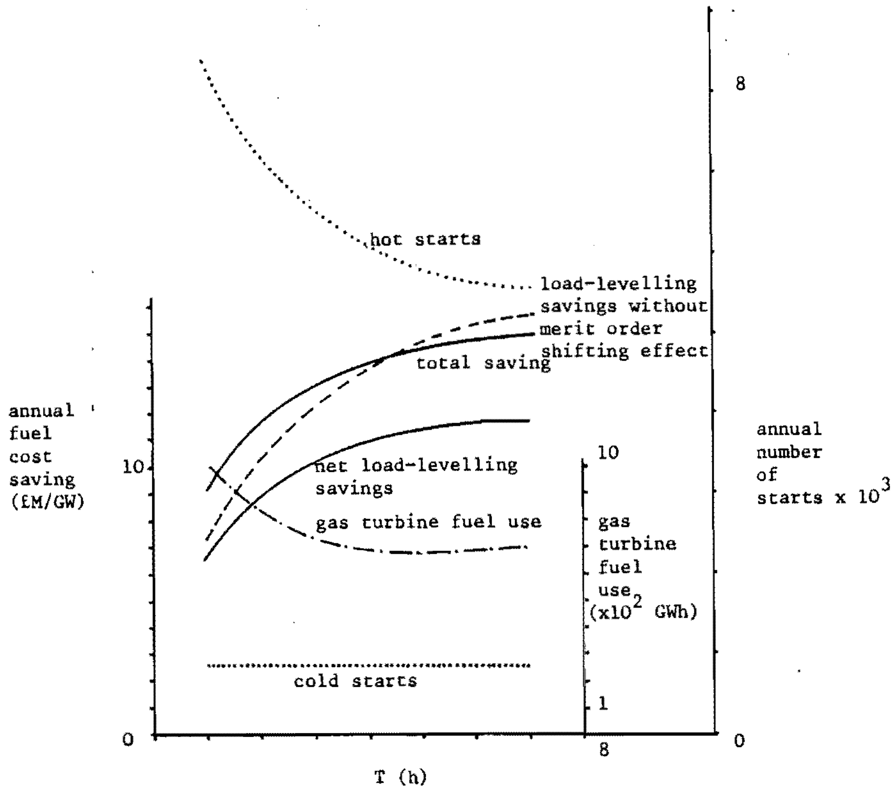


Figure 4 : Breakdown of savings due to storage (3 GW penetration)



Splitting the load-levelling saving into its two components reveals, as expected, that for reasonable storage durations (ie T > 2 hours) the impact of merit order shifting is negative. In other words, there is a fuel penalty arising from such plant substitution. Storage is net consumer of energy in this context, which explains the CEGB position. Overall, though, it is clear that the net result of load-levelling is a significant fuel saving as the benefit of smoothed operation outweighs the merit order shifting penalty. This explains why the results presented in Figure 1 are at variance with CEGB statements. The overall savings attached to storage are in fact greater at high penetrations than the official CEGB analysis would indicate.

Figures 3 and 4 present analogous results for the cases of 2000 MW and 3000 MW storage penetrations (also with η = 0.90). Merit order shifting penalties increase with storage penetration but the net load-levelling savings are increasingly significant. The reduction of savings per GW of installed storage with storage penetration reflects the fall in the marginal value of storage as described in relation to Figure 1.

Clearly the merit order shifting penalty is dependent on η and Figure 5 shows that for perfect storage (η = 1.0) all penetrations give a positive merit order shifting saving, as expected. The intermediate efficiency of 0.95 results in almost no merit order shifting effect. At low values of T, ie small storage capacities, a small saving is seen but above some critical value this is translated into a small penalty. However, the net effect in all cases, is a significant overall load-levelling saving.

Some of the results are re-presented in Figure 6 to show the impact of η on the marginal savings with increasing penetrations. The fact that in 6(c) (perfect storage) the load-levelling savings with different storage penetrations are much more closely grouped than in 6(a) (η = 0.9) reveals that higher storage efficiencies permit storage penetration to increase without such a marked fall in the marginal savings. (Also see Figure 1). This should come as no surprise. Operational savings, as indicated by the number of hot starts, are strongly dependent on storage penetration but fairly insensitive to efficiency as shown in Figure 7.

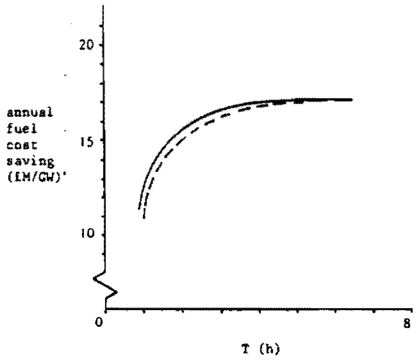
The significance of these results lies in the conclusion that even in the near term future (1985) additional storage on the CEGB system could give rise to appreciable running cost savings for the system as a whole. Should high efficiency electricity storage systems become available the benefits would obviously be greater. The economic case will of course also depend on the capital cost of storage. A more complete analysis is presented in Section 6.

4.3 Storage as immediate reserve

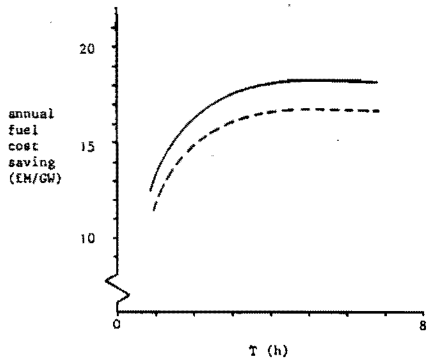
At this point it is appropriate to introduce the consideration of storage as 'immediate reserve' capacity. Two approaches have been used to estimate the value attributable to this particular function of storage which, it may be recalled, cannot be dealt with by the simulation model. Nevertheless, some results from the model will be useful as inputs to the analysis.

Figure 5 : Merit order shifting savings/penalties for high storage efficiencies

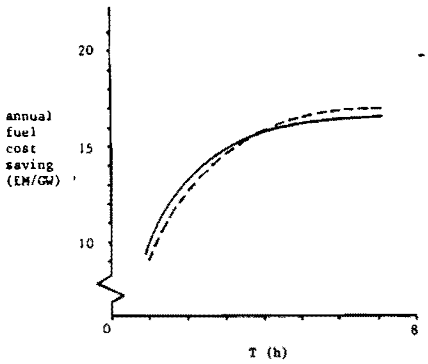
Key : ——— net load-levelling savings
- - - - load-levelling savings without merit order shifting effect



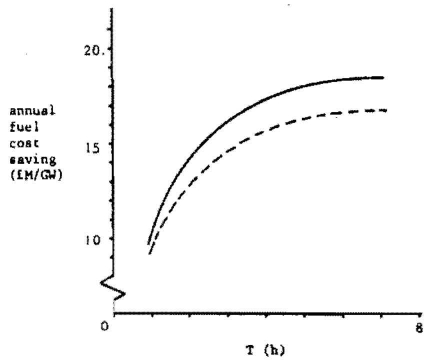
(a) 1 GW η =0.95



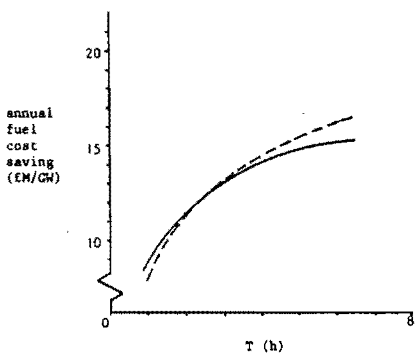
(b) 1 GW η=1.0



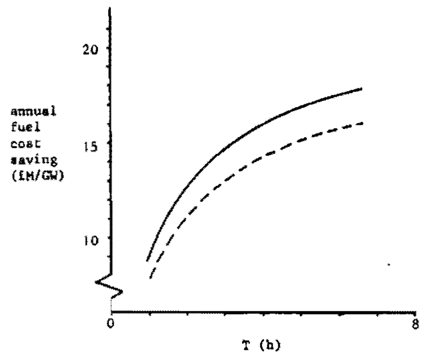
(c) 2 GW η =0.95



(d) 2 GW η =1.0

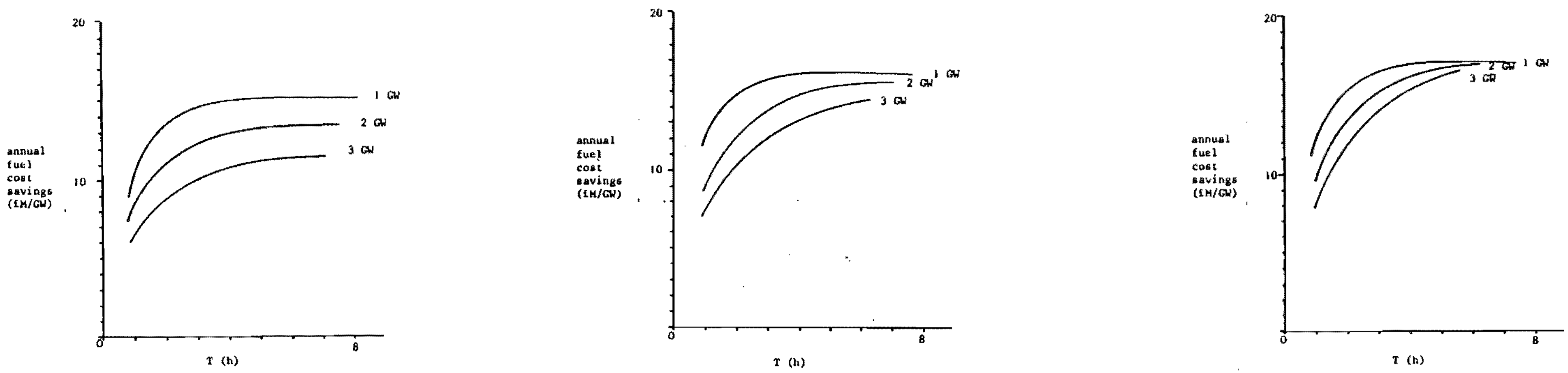


(e) 3 GW η =0.95



(f) 3 GW η =1.0

Figure 6 : The effect of increasing storage penetrations on total annual fuel cost savings

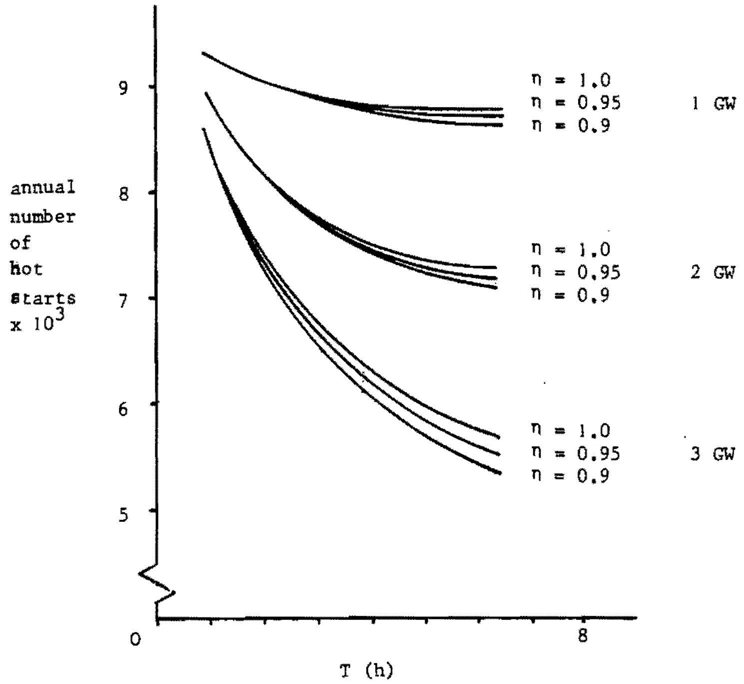


(a) η =0.9

(b) η =0.95

(c) η =1.0

Figure 7 : The effect of storage on the number of hot starts on conventional thermal plant



4.3.1 Method 1 (which makes direct use of the hourly simulation model)

Results from an hour by hour simulation of the 1985 projected electricity supply system are used to estimate the fuel cost penalty associated with holding 660 MW of spinning reserve on fossil fuelled steam plant. The CEGB has indicated [17,23] that this amount is required, over and above reserve for scheduling and dispatching errors and frequency control, to provide supply in the event of a major plant loss (either through plant failure or infeed loss).

The model allows a fixed amount of spinning reserve, held on thermal plant, to be specified (and SR1 is set to zero), but some of this will be used to deal with uncertainties in demand, thereby saving use of gas turbine plant. In reality immediate reserve will not be used in this way and the results from the model must be modified to take account of this.

Two annual simulations were performed with all factors other than spinning reserve fixed, and no storage. This allowed the fuel cost of keeping 660 MW of spinning reserve on steam plant to be evaluated. As previously mentioned, the simulation model does not account for plant failures or maintenance and therefore we have to approach the evaluation of storage for security of supply in this roundabout way.

The results are:

	Fixed spinning reserve (MW)	Steam plant fuel cost £ (M)	Gas turbine fuel cost £ (M)
Run 1	0.0	3034.61	23.64
Run 2	660.0	3057.82	1.24

where all fuel costs are for March 1981.

We see that a considerable amount of spinning reserve has been used to substitute for gas turbine generation. It is necessary to correct the steam turbine fuel cost penalty to take this into account since we require the cost penalty of an extra 660 MW of reserve which, in the context of the model, is never used.

The £22.4M of gas turbine fuel saved corresponds to 444 GWh of electricity which in the model has been provided from spinning reserve on thermal plant. If we assume that the efficiency of steam plant making this contribution is given, in the first approximation, by the average steam plant efficienty in Run 2, then we can estimate the fuel cost as follows:-

$$\text{fuel cost per unit generated on fossil fuelled thermal plant} = \frac{\text{total cost of fuel for steam plant}}{\text{annual steam turbine output.}}$$

Since the model gave 172052 GWh of steam turbine output we have

$$\text{fossil fuel cost per unit} = \frac{3057.82}{172052} = 0.0178 \text{ (£M/GWh)}$$

The fuel cost associated with saving gas turbine generation is therefore:

$$0.0178 \times 444 = 7.89 \text{ (£M)}$$

The corrected annual cost of holding 660 MW of spinning reserve is thus given

by:

$$(3057.82 - 7.89) - 3034.61 = \underline{15.3} \text{ (£M)}$$

and this is the annual saving which can be credited to storage satisfying the immediate reserve requirement of the system.

4.3.2 Method 2 (based upon the decrease in efficiency with part loading of an average steam plant unit)

The appropriate 'average' steam plant from the merit order is the 'average last in line' plant operating since it is expected that spinning reserve will be held on sets at the bottom of the merit list (of those sets operating at any one time). The assumptions of the model, which are to an extent validated (see Appendix 1) can be useful in calculating this 'average last in line' efficiency. 85 fossil fuelled steam plants, rated at 500 MW each, are assumed to exist with full load efficiencies decreasing lineally from 0.375 to 0.304. The 'average last in line' plant is the plant furthest down the simulated merit order which is operating at the annual average system load of 24.95 GW. Since a constant nuclear component of 5.31 GW is assumed for 1985 this leaves the average load on conventional thermal plant as 19.64 GW which requires 40 of the 500 MW units to be operating. The efficiency of the 40th unit is given by:

$$0.375 - ((39/84) \times (0.375 - 0.304)) = 0.3416$$

It is conventional to describe the decrease in efficiency of plant with loading by the Willans line. Again from the modelling assumptions this is given by

$$F_{LF} = F\,(0.15 + 0.85\,LF) \qquad (4.1)$$

where F is the fuel consumption at full load and F_{LF} is the fuel consumption at part load LF. It should also be mentioned here that this and other assumptions of the model were adopted after full discussions with CEGB representatives as well as plant operators.

The cost of steam plant generation at 100% efficiency is taken as 0.6081 p/kWh = 6.081×10^{-3} £M/GWh.

If η is the full load plant efficiency the fuel cost of generation is

$$C = 6.081 \times 10^{-3}/\eta \text{ £M/GWh} \qquad (4.2)$$

The part load efficiency η_{LF} is given by

$$\eta = k.R/F \text{ and } \eta_{LF} = k.\frac{R.LF}{F_{LF}}$$

for some k, ie using (4.1)

$$\eta_{LF} = \frac{\eta \text{ LF}}{(0.15 + 0.85 \text{ LF})}$$

The cost of generation at part load LF is thus

$$\frac{C \times (0.15 + 0.85 \text{ LF})}{LF} \quad \text{£M/GWh} \qquad (4.3)$$

The fuel cost penalty per GWh generated is therefore given by the difference of equations (4.2) and (4.3), ie

$$\frac{C\ ((0.15 + 0.85 \text{ LF}) - LF)}{LF}$$

$$= \frac{C \times 0.15\ (1 - LF)}{LF} \qquad (4.4)$$

The total electricity generated per year at load factor LF is

$$LF \times R \times 24 \times 365 \times 10^{-3} \text{ GWh/annum} \qquad (4.5)$$

where R is the plant rating in MW.

The annual fuel cost penalty is thus, from (4.4) and (4.5)

$$C \times 10^{-3} \quad 24 \times 365 \times 0.15\ (1 - LF)\ R \quad \text{£M/annum}$$

Since the total amount of spinning reserve made available by running the plant on load factor LF is

$$R\ (1 - LF)\ MW$$

the annual fuel penalty per MW of spinning reserve is, using (4.2)

$$\frac{6.081 \times 10^{-6} \times 24 \times 365 \times 0.15}{\eta} \text{ £M/MW annum}$$

The fuel penalty for holding 660 MW of spinning reserve is thus

$$660 \times 6.081 \times 10^{-6} \times 24 \times 365 \times 0.15/\eta \text{ £M/annum}$$

$$= 5.27/\eta \text{ £M/annum}$$

With η taken as 0.3416 ('average' end of merit order plant) the annual fuel penalty is thus

$$\underline{\underline{15.4}} \text{ (£M)}$$

This compares well with the result obtained by Method 1.

Should the CEGB increase the size of their largest unit to 1320 MW in the 1980's[24] the value of storage able to replace the spinning reserve required for immediate standby would increase to about £31M per annum in 1981 prices.

Discussion so far has avoided the question of how much storage capacity would be required for this function, the rating being either 660 MW or 1320 MW according to the maximum single unit size on the system. This will depend on what means is adopted to make good the level of spinning reserve from standing reserve, which is plant not in synchronism with the system but able to provide load in five minutes. Any capacity transferred to spinning reserve is in turn made good from standby reserve which usually consists of 700 MW of plant which can be loaded within two hours as required and is provided normally by gas turbine plant.[25] How the system will be operated when large amounts of storage are available (ie after Dinorwig is commissioned) has not yet been published by the CEGB and thus estimates of storage capacity to be allocated to this role for the purposes of economic assessment must be speculative at this stage. It may be assumed that storage would continue to supply the load, after a major generation or infeed loss, until further steam turbines could be brought on (four to five hours).* Detailed calculations will not depend on this aspect of storage utilisation. We are now in a position to make a rough estimate of the annual fuel cost savings provided for the CEGB by Dinorwig.

4.4 Fuel cost savings provided by Dinorwig

For providing 660 MW of immediate reserve an annual credit of about £15.4M is indicated by the above analysis. Since provision of this standby would entail two of the six Dinorwig turbines to be kept spinning in air the effective remaining storage rating would be 1120 MW.

The projected efficiency for Dinorwig is 0.88 [26] so that results from Figure 1 for η = 0.90 can be used. The total saving for the first 1.1 GW of storage is about £26.7M.

*Actual practise will of course depend on recalculated marginal costs of generation on different available plant which in turn will depend on the time expected to clear the fault. The CEGB's planned on-line monitoring and control aiming at optimum use of resources, is expected to deal with this complex problem.

This gives a reasonable indication of the value of Dinorwig (setting aside the existing Ffestiniog capacity) for roles other than immediate reserve. Our optimisation indicated that about 90% of the storage capacity (GWh) should be allocated for load-levelling with the remaining 10% being intended for use as spinning reserve (here including the effect of scheduling and dispatching errors). Figure 2 indicates that roughly 60% of the total savings indicated by Figure 1 should be attributed to load-levelling and the remaining 40% for spinning reserve. Table 1 below presents these results.

Table 1 : Estimated savings from Dinorwig (1981 prices)

Storage application	Annual saving (£M)	% of total saving
660 MW of immediate reserve	15.4	37
Reserve for scheduling and dispatching errors	10.7	25
Load levelling	16.0	38
All functions (ie total savings):	42.1	

CEGB estimates[23] give 45% of the overall operating-cost benefit for peak lopping in merit order, 40% for immediate reserve and 15% for frequency regulation.* Total savings of £45M per annum (1982) were estimated. The figures in Table 1 are in broad agreement with these projections although it should be remembered that the savings due to load-levelling resulted primarily from eased operation of plant rather than 'in merit' generation as is the case in the CEGB estimates.

*We have not considered quantitatively the advantages of providing frequency regulation with storage which reduces the need for sets to run on governor action and thereby increases their efficiency. On the other hand the CEGB have not published estimates for savings relating to reserve for scheduling and dispatching errors.

5 Distribution and transmission aspects of electricity storage

As previously mentioned, the foregoing analysis was based on the assumption of lumped or centralised generation and consumption. In reality the system is far from this ideal with a large proportion of the capital cost tied up with the transmission and distribution sub-systems. The losses and thus the impact on generation efficiency are, however, minor and provide the justification of the centralised modelling approach.

Despite these conclusions it is worthwhile to briefly review the distribution and transmission aspects of electricity storage.

Of relevance to the value of Dinorwig is the realisation that transmission losses will be higher than average. This is because it is to be used to provide for virtually all the CEGB spinning reserve requirement, much of which will be used at locations geographically distant from Dinorwig in north-west Wales. It is presumably this very problem, together with the need for local transmission reinforcement, that provides encouragement for the development of pumped storage installations close to major load centres. Such a proposed scheme is the 1500MW pumped storage power station suggested for Longendale in the Peak District National Park [27,28] (close to several highly-populated areas).

A very rough guide to the increased transmission losses associated with generation from Dinorwig is provided by the calculation in Appendix 2.

It suggests that about 6% of the net output from Dinorwig will be lost in transmission. This compares with a national average of about 2.6%. Losses from the charging of Dinorwig (pumping) are unknown as they depend on the location of sets suitable for surplus base-load operation.

We now move on to the additional savings which can be credited to distributed storage. For the CEGB the optimum location (for example for distributed battery storage) appears to be at the 11/33 kV substations.[13] Our consideration will be more general and will not be concerned with specific siting details. On the other hand wider applications of storage, such as those encompassed by load management, can be dealt with.

Restrictions on resources available for the study have meant that only a highly simplified approach has been possible for the assessment of transmission and distribution aspects of storage. Complex and costly approaches of the sort applied to various small American utilities [29,30,31] (which are, incidentally, much easier to analyse than the UK system) were thought to be inappropriate at this stage. Moreover, the results of these studies are on the whole inconclusive and heavily dependent on the plant mix of the utility under consideration.

The present study again makes use of the hourly CEGB load data for 1978. Transmission and distribution losses are assumed to be predominantly I^2R losses (ie copper losses in transformers and line losses are included but iron losses of transformers are excluded). This is in line with the assumption made in a major American study [29] and is also supported by the formula for load loss-factor given by Weedy [32] for Great Britain:

$$\text{Load Loss-Factor} = 0.2\ (\text{Load Factor}) + 0.8\ (\text{Load Factor})^2 \qquad (5.1)$$

However, it is not possible, as will be demonstrated later, to use the above formula directly to evaluate changes in losses attributable to storage as sometimes suggested.

A further, but important, restriction of the technique adopted is that all parts of the transmission and distribution system are assumed to experience the same load profile. Clearly the absolute magnitude of power flows in different parts of the system need not be the same, but the relative values will assumed to be, ie if a(t) and b(t) are two load curves

$$a(t)/b(t) = \text{constant} \quad \forall t.$$

Another way of expressing this is to say that the diversity factor [30] is equal to unity. The coincidence factor defined as the reciprocal of the diversity factor will then also be equal to unity. This approximates well to the load experienced by substations but is less accurate for the load profiles of residential customers, for which the associated savings will, in consequence, tend to be underestimated.

The effect of dispersed storage is to reduce the effective load on the system during its discharge period and to increase the effective load during its charging period, ie it smoothes the system load profile. Since the on-peak losses are much higher than the off-peak losses, the operation of the dispersed storage device which increases the off-peak transmission and distribution losses but reduces the corresponding on-peak losses will result in a net energy saving.

A computer model was developed to assess these savings through calculation of the mean square load for different amounts of storage used for daily load smoothing. It was found simplest to express the savings as a function of the total storage capacity in GWh. Savings are given as a percent of losses and can thus be applied to savings in both transmission and distribution losses.

Figure 8 shows the results which depend crucially on the storage efficiency, indeed for a one-way efficiency of 0.8 (an overall efficiency of 0.64 since no standing losses have been included) or less, losses will actually increase (a point not made in the American studies). This is because the rise in average load more than compensates for the reductions of peak losses. Maximum savings are achieved when the diurnal variations are completely removed, preferably with no rise in the average load (η = 1.0), which occurs for storage capacities in excess of about 40 GWh. Also it is clear that, depending on efficiency, the impact of successive additions of storage produce smaller and smaller savings. Only about 10 GWh of dispersed storage would be required to realise most of the available savings for a round-trip efficiency of 0.8 (η = 0.9).

That the formula for load-loss factor is not useful in calculating these savings can be demonstrated by a simple example.

The load factor for 1978 is given by:

$$\text{Mean load/Peak load} = 24.9/43.6 = 0.57$$

and thus the load-loss factor is, from equation (5.1), 0.375. With perfect daily smoothing the new load factor is found to be 0.92 and the load-loss factor becomes 0.874. Since the load-loss factor is defined to be [32] the ratio of the average transmission loss to the loss at peak load, the average losses with storage should be given by:

Figure 8 : Reductions in transmission & distribution losses due to distributed storage

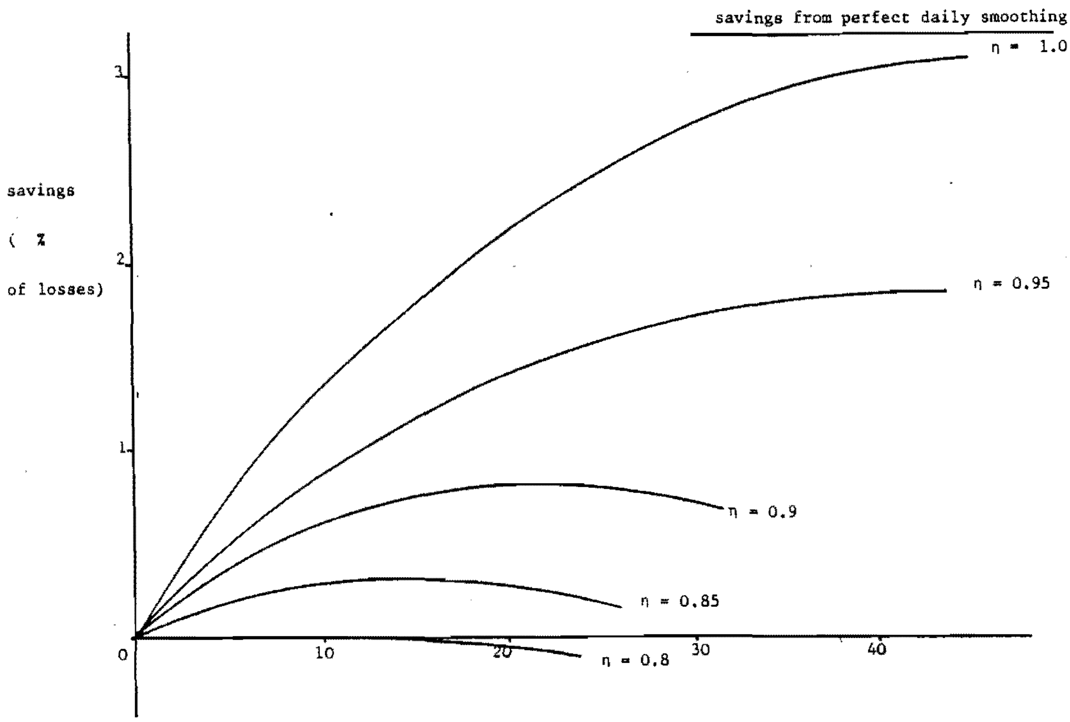
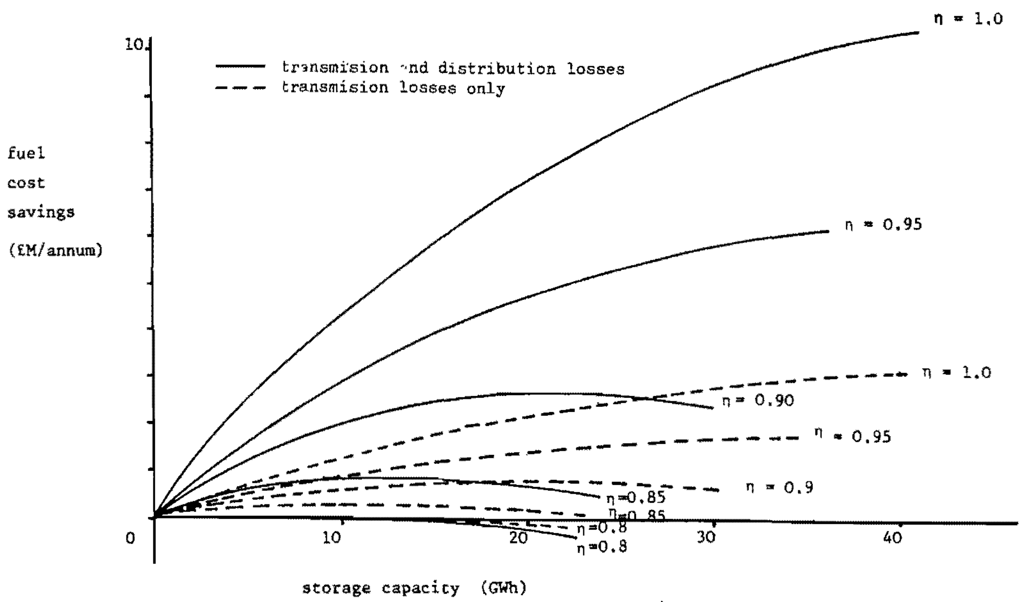


Figure 9 : Annual fuel cost savings derived from distributed storage



$$\text{average losses with storage} = \frac{\text{load loss factor with storage}}{\text{load-loss factor without storage}} \times \frac{\text{peak losses with storage}}{\text{peak loss without storage}}$$

$$\times \text{ average losses without storage}$$

$$= \frac{0.874}{0.375} \times 0.38 \times \text{average losses without storage}$$

$$= 0.89 \times \text{average losses without storage}$$

This gives an 11% reduction in losses which is clearly incompatible with the 3.2% calculated by the more detailed approach. The reasons for this are concerned with the variation with load shape of the impirical factors, 0.2 and 0.8, in equation 5.1.

We now come to the question of the value of these savings. This will depend on the extent to which storage is dispersed and we will consider only two cases. Storage at the interface between the transmission and distribution networks, and at the point of end use. If we assume, pessimistically, that the average cost of generation saved is given by the average cost of generation on conventional steam plant, then the annual saving can be estimated as follows for the CEGB network.

Based on 1978 data [33,34] the losses for distribution and transmission are 8.6% and 2.3% respectively. The mean system load was 24.9 GW and the total useful output was 21.8×10^4 GWh. The maximum achievable saving for diurnal smoothing of 3.2% of the losses translates into actual savings* as represented in Table 2 below.

Table 2 : Transmission and distribution savings from diurnal smoothing

Type of losses	GWh/annum	£M/annum
Maximum Savings in distribution losses	601	9.0
Maximum Savings in transmission losses	161	2.4

Figure 9 shows the annual savings as functions of GWh of storage. For interest Table 3 shows the maximum achievable savings if weekly and interseasonal storage are considered.

Table 3 : Savings from weekly and interseasonal storage

Savings in £M/annum	Weekly smoothing	Interseasonal smoothing
Distribution system	11.8	20.3
Transmission system	3.1	5.4

*As in the rest of this report all costs are based on 1981 values.

Comparing these figures with those derived for the annual savings from Dinorwig we see that distributed storage does in fact providé a significant addition to running cost savings. This is on top of any capacity credit resulting from the postponement of transmission and distribution reinforcement, which will not be dealt with in this preliminary study. It may be recalled that the CEGB 1981 estimate of credit for battery storage installed at 33/11 kV substations was £6/kW per annum.[13]

A number of technologies could provide high efficiency distributed electricity storage. These include advanced flywheels,[35,36,37] advanced batteries [13,38,39] and fuel cells/electrolysis.[40,41,42] Electric storage radiators can to some extent be regarded as distributed electricity storage although it should be pointed out that with an overall estimated efficiency of about 70% little saving in transmission and distribution losses would be achieved.

As stated in Section 2, load management is in many respects akin to storage. The system savings arise primarily from the smoothing of the load profile in exactly the same way as for centralised and distributed storage, and it is clearly much cheaper than explicit storage. The extent to which load management techniques could be applied is presently unknown although a few studies of particular domestic systems are underway in the UK.[43,44,45] American studies, in particular the Edison Electric Institute's [46] seem to have confused the picture by adopting methodologies which imply much smaller benefits than are appropriate. Given the understandably limited interest of the CEGB and the lack of fundamental research by other bodies there remains significant scope for research. The primary need would appear to be for an evaluation of degree to which load management can be applied before limitations in intrinsic storage start to manifest themselves in terms of reduced satisfaction of end use requirements.

Load management techniques may also be used to help accommodate large abnormal loads on power systems.[47]

6 A brief review of electricity storage economics

The study so far does not warrant an in depth economic analysis, it would however be remiss to make no mention at all of this aspect since storage will not be purchased if the capital costs outweigh the economic benefits (ie system running cost savings).

As pointed out on a number of occasions in this study, capacity credit aspects of storage (with respect to generation, transmission and distribution) will not be dealt with. First, because of the inappropriate nature of such an approach to a system containing significant surplus capacity (notably in generation and transmission), and second, because the estimation of economic value to be attributed to these credits would be highly speculative.

Instead we will examine the cost effectiveness of storage as a fuel saver for the generation system as a whole. Standby losses and maintenance costs have not been included for the storage system but this is roughly compensated for by the reduction in maintenance expected for conventional plant (mentioned in Sections 2 and 4). The lifetime for large scale centralised storage is taken as 40 years although this will underestimate the savings for a pumped hydro installation such as Dinorwig. This and other parameters assumed for the analysis are given in Table 4 below.

A standard net present value (NPV) approach has been adopted. For the purposes of optimisation the rate of return on capital has been maximised, this is calculated as the rate of return which gives a NPV of zero.[48] It is interesting to establish, for a particular storage penetration, the optimum value of T (defined in Section 4 as storage capacity per unit storage rating). Savings attached to load-levelling were thought to be relevant in this context and based on these (taken from Figures 6, 7 and 8) the figures given in Table 5 below were calculated.

Table 4 : Parameters assumed in the economic analysis

System lifetime	:	40 years
One-way storage efficiency	:	0.9
Storage standing losses	:	zero
Real fuel inflation	:	zero
Capital cost of storage:		
Cost of storage rating	:	£170M per GW
Cost of storage capacity	:	£10M per GWh

Table 5 : The economics of large centralised storage (eg pumped hydro) for load-levelling

Storage Rating (GW)	Optimum T (hours)	Optimum rate of return(%)
1	3.5	12
2	4	8.5
3	4.5	6.5

It should be mentioned that, around the optimum values of T the economic performance was insensitive to variations in T and thus values in the range within one or two hours of the optimum would not be unattractive. Table 5 also shows that storage penetrations up to 3 GW conform to the requirement of at least a 5% return on capital laid down by the Treasury for large capital expenditures by, for example the CEGB.

If the additional savings (about £15M per year), from the 'immediate reserve' function of storage, had been included, the rates of return would have been higher still.

It can also be seen from Table 5 that the optimum value of T increases with storage penetration which is not unexpected given the shape of the load profile (Figure A1.1 in Appendix 1). The values of T given in the table are averages for the total storage available in the case considered. These can be translated into values of T associated with successive tranches of storage as shown in Table 6 below (for 1000 MW tranches).

Table 6 : Optimum storage durations for successive tranches

Tranches of 1000 MW	Optimum T for each tranch (hours)
first	3.5
second	4.5
third	5.5

As previously mentioned all of these figures could easily be increased by two hours. These can be compared with CEGB estimates[16] although it should be remembered that the load-levelling savings arise in a different manner.

If the savings resulting from the reduction of transmission and distribution losses are included, storage more expensive than pumped hydro can be considered. Further research is needed in this area.

7 Conclusions

Although numerous papers, reports and articles on the topic of electricity storage exist these tend to be either reviews [10,16,49,50,51,52] or studies of particular technologies. [11,13,53,54,55,56,57] Little attention had been paid to system aspects although a number of papers have been addressed to the complex problem of optimum storage scheduling.[15,58,59,60,61] The study presented here has, albeit in a simple manner, attempted to quantify the system effects of storage as it would apply to the CEGB system. Renewable power sources have not been included but the interaction of storage and renewables on an electricity generation system has already been dealt with in a number of studies [7,8,9,62,63] and in any case, renewables can be reviewed as simply increasing scheduling errors.

The conclusions, applicable to plant mixes not dissimilar to the one expected in 1985, suggest that significant additions to centralised electricity storage would be economically justified by fuel savings alone. Should high efficiency systems such as superconducting magnetic energy storage or kinetic ring energy storage [64] become available, greater savings could be made and higher penetrations would be permissible.

It has been shown that a major contribution to the savings is made by the reduction of hot starts and standby operation of conventional thermal plant. The effects of merit order shifting are indicated by the model to be far less important, although it should be pointed out that restrictions in the modelling approach mean that the benefits of 'in merit' generation by storage (primarily at peak loads) will be underestimated. However, the conclusion that storage should generally be used for load-levelling still applies.

Additional benefits for distributed storage have been calculated, most significant when the storage is at the point of end use and highly efficient, suggesting that load management techniques may also have a significant potential. This is an area which to date has received little attention especially with regard to quantitative system effects. A recent review has been provided by Cory[65] in evidence to the Sizewell 'B' inquiry.

Should the component of nuclear plant in the CEGB generation mix increase significantly the value of additional electricity storage will be appreciably enhanced. For reasons outlined earlier, this scenario has not been studied. Reasonable estimates for savings provided by storage in a heavily nuclear generation system are available from a number of CEGB studies [10,11,13,16] It should be pointed out, however, that should storage be necessitated by the inability of nuclear plant to two-shift then, strictly, the costs of nuclear generation, in comparison to coal fired generation, should include the concomitant storage costs.

Appendix 1 : A detailed description of the large scale electricity generation simulation model

As outlined in Section 4 the computer simulation model is based on an hourly time-step, ie it uses hourly load data (supplied by the CEGB) and simulates the operation of the complete generation system hour by hour.

A1.1 Types of generation included

Electricity generating plant is divided into nuclear, fossil-fuel steam turbine, gas turbine and storage plant.

Nuclear stations are assumed to give a constant output throughout the simulation period, ie they cannot be used for load-following. No problems arise with this strategy since, in all the studies considered here, the nuclear output does not approach the minimum system load.

In any given hourly period the model attempts to meet the system load first by using steam turbines, then if necessary by discharging storage (if available) and lastly by using gas turbines. Within the context of the model, gas turbines and storage are assumed to respond instantaneously, this is reasonable as their actual response times (seconds to minutes) are short in relation to the hourly time-step of the model.

A1.2 Steam turbine plant modelling

The model version used for this study assumes there to be 85 steam turbine units all rated at 500 MW and all subject to a start-up time from cold of eight hours. They are used in merit order (with no account of plant availability) specified by a linearly decreasing full-load efficiency, where the efficiency of the first unit is taken as 37.5% and the last unit (no 85) as 30.4%*. This gives a decrease in efficiency per unit of 0.085% which is found to give approximate agreement with the CEGB system, although of course direct comparison cannot be made first because available CEGB figures are for overall efficiency and not full-load efficiency and second because no account of plant availability is taken in the model. (See later for discussion of validation).

Once a unit is generating, it can be operated at any level from full-load down to a part-load limit taken as 50%. It is further assumed that any change in output between these limits can occur within a time-step. Part-load efficiency is given by a Willans line, ie the fuel consumption at part-load PL% (as a fraction of the fuel consumption at full-load) is specified by**

$$0.15 + 0.85\,(PL/100)$$

Fuel use is also specified during the start-up sequence as 0.109 times the full-load consumption for the hour in question.** In addition a unit can be held on standby at any level of readiness between cold and hot. On n-hour standby (n hours from generation) the resulting fuel use is 0.01875 (8-n) times full-load consumption.

* Efficiencies are based on the net calorific value of fuel.
**Footnote over page

The rate of plant cooling is assumed to be equal to the rate of heating, in other words a plant that has been cooling from a given state of readiness for say three hours will require a further three hours to return to the same state of readiness. The model keeps a record of the status of each of the 85 units which is updated every hour.

A unit not required in a given hour but expected to be needed again within four hours is kept running at the part-load limit in order to avoid unnecessary synchronisation. This means that other units will have to be part-loaded to compensate for the surplus generation. In addition, if a unit is not needed within four hours but is expected to be required within the current day it is kept on one-hour standby to avoid excessive cycling.

Should one or more units be running part-loaded in any hour surplus power is, if possible, used to recharge storage.

Because of the eight hour start-up time of the steam turbines it is necessary to predict the plant requirement up to eight hours ahead. This is done by predicting the demand for the hour in question, adding any spinning reserve requirements (which are treated as notional load) and when storage is used for load-levelling, making the appropriate adjustment as explained below.

To ensure that sufficient steam plant units are started the eight-hour forecast is repeated each hour. However, due to load prediction error, the actual system demand may be different from that expected and this could result in insufficient steam plant available. Since additional thermal units cannot be brought on line at such short notice, alternative plant (storage and gas turbines in that order) is used. In the other hand if a surplus of plant occurs (even after the maximum amount is used to charge storage) output is reduced by successively part-loading plant further up the merit order.

Spinning reserve as already mentioned is treated in the model as a notional extra load. It is provided by operating a sufficient number of steam turbine units at part-load, the total reserve available being given by the extra output provided by moving all part-load plant to full-load status in a given hour.

As mentioned in Section 4 the model includes two important control parameters; SR1 the amount of spinning reserve on steam plant specified as a fraction of the predicted system load, and QSF which will be dealt with under storage. It is acknowledged that in practice spinning reserve strategy is more complex with system operators responding to seasonal daily and hourly variations and even to scheduled television programmes. Despite this it is felt that useful guidelines are provided by changes in system performance with SR1.

**Data recently provided by the CEGB[66] suggests that 0.15 may be too high a figure for the no load fuel consumption, 0.12 to 0.13 would perhaps more accurately represent plant toward the bottom of the merit order. Start up costs are found to be highly variable and dependent on plant type and rating. The figures assumed fall within the range provided by CEGB data. Discussion of the significance of these points is included in the section on model validation.

Optimum values of SR1 are usually found to be slightly negative (ie enough steam turbines are started to meet slightly less than the predicted demand) with a resulting small increase in the use of storage and gas turbines.

A1.3 Electricity demand and load forecasting

1978 CEGB hourly load* data is used in the model to provide the forecast demand in any hour upon which the scheduling of steam plant and planned load-levelling depend. The 'actual' demand is produced from the forecast demand by multiplying by a randomising factor taken from a normal distribution with mean 1.0 and a standard deviation of 0.015. In this way an element of demand uncertainty (or forecasting error) is introduced, which is of a magnitude comparable to that on the CEGB system over a similar timescale.

A1.4 The '1985' plant mix

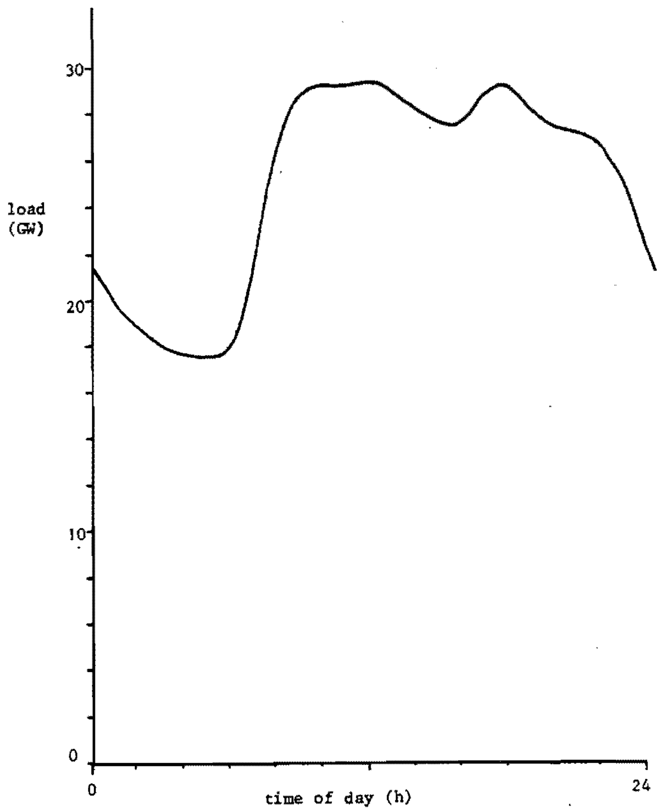
This study is based on a plant mix to be expected on CEGB system in 1985. The plant mix was projected from the existing mix on the basis of knowledge of stations under construction and the plant lifetimes given in the CEGB's statement of case for Sizewell.[67] In the simulation model the steam turbine capacity required is that

Table A1.1 : Model input parameters

Time step:	1 hour
Load data:	Demand on CEGB system, 1978 plus randomising factor.
Maximum Demand (MW)	44758
Minimum Demand (MW)	9907
Total Demand (GWh)	218597
Uncertainty Factor	Normally distributed, mean 1.0, standard deviation 0.015
Nuclear Plant capacity:	8170 MW
Output	Constant 5310 MW (ie 65% load factor)
Steam Turbine plant:	42500 MW (ie 85 units of 500 MW each)
Start-up time	8 hours
Part-load Limit	50%
Full-load efficiencies	37.5% decreasing linearly to 30.4%
Fuel use, relative to full load consumption	(0.15 + 0.85 (LF/100) at LF% load (0.109) during start-up (0.01875 (8-n) at n-hour standby
Gas turbine plant:	Effectively instant start-up
Rating	3450 MW
Generation costs (March 1981 prices)	
Steam turbine fuel costs	0.6081p/kWh (thermal)
Gas turbine fuel costs	5.0428p/kWh (electrical)

*Figure A1.1 shows the annual mean daily low profile for the data used.

Figure A1.1 : 1978 average daily load profile used in study



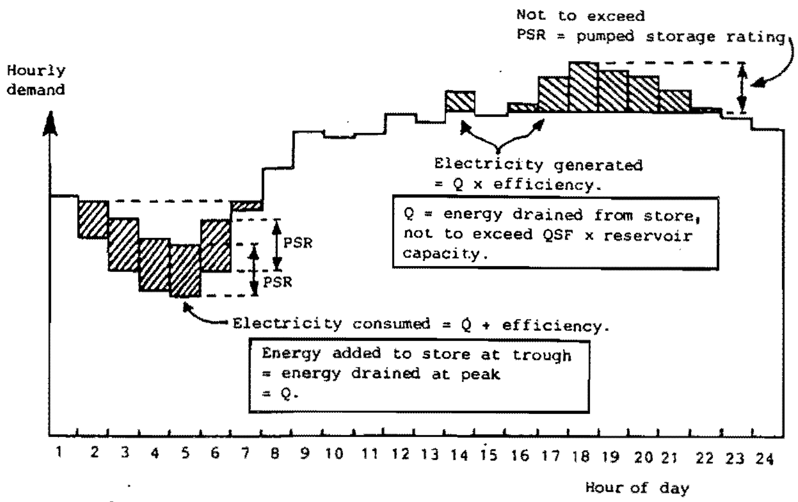


Fig. A1.2 Schematic Illustration of Load-levelling Strategy
(taken from Bossanyi and Halliday[5])

presumed to be available for operation at the time of peak annual demand. Thus the steam turbine capacity expected in 1985 was multiplied by expected winter peak availability factor of 0.86.[67] Steam turbine full load efficiencies are based on CEGB figures for 1981-82 [68] and fossil fuel costs used are in March 1981 prices. Full details of inputs and assumptions made are included in Table A1.1.

A1.5 Storage modelling

Storage is characterised (for the model) by a storage capacity in GWh, a rating or maximum charge/discharge rate in MW and a one-way efficiency, η .(It is assumed that the efficiencies of charging and discharging are equal, ie. the overall cycle efficiency for the store is η^2). No standing losses are included.

Spinning reserve can be provided by storage as described above but in addition the model provides the option of load-levelling whereby storage is charged during the night-time demand trough so that it can be used to help meet the subsequent afternoon/evening peak. This has the advantage that generation from low-merit less efficient units at the peak is replaced by generation from higher-merit units at the trough. The value of this merit order shifting depends critically on the storage efficiency as discussed at some length in the main text. Nevertheless the availability of storage for levelling off the peak can mean that several extra steam turbine units may not be needed at all and can be left cold, thus reducing start-up and standby losses.

Using storage for load-levelling reduces its availability as spinning reserve. To take account of this and improve storage utilisation a further control parameter, QSF, has been introduced, which specifies a fraction of the storage which can be used in planned load-levelling, the remainder being available as spinning reserve.

A load-levelling algorthm developed by E A Bossanyi[4] is called by the model at the start of each day and uses the predicted load profile for the day to calculate a new 'levelised' profile. The storage capacity used by the routine is QSF times the total storage capacity. The following constraints are included:

i) in any hour, the charging or discharging rate cannot exceed the storage rating.

ii) The same amount of energy, Q, is added to the store during the trough as is supplied from it at the following peak.

iii) Q must be less than or equal to QSF times the total storage capacity.

Under normal circumstances the daily peak is smoothed to a flat plateau at a level of the peak demand minus the storage rating, as illustrated in Figure A1.2 (taken from Bossanyi and Halliday [5]). The trough is filled in subject to i) and ii) above but this does not result in a flat bottom as shown in Figure A1.2.

The new 'levelised' profile is calculated according to the above rules by a simple iterative procedure and then used in place of the predicted load in scheduling steam plant as previously described. Storage is then used as required in any given hour which usually results in load-levelling roughly as planned, but with storage still available to cope with forecasting errors.

A1.6 Model validation

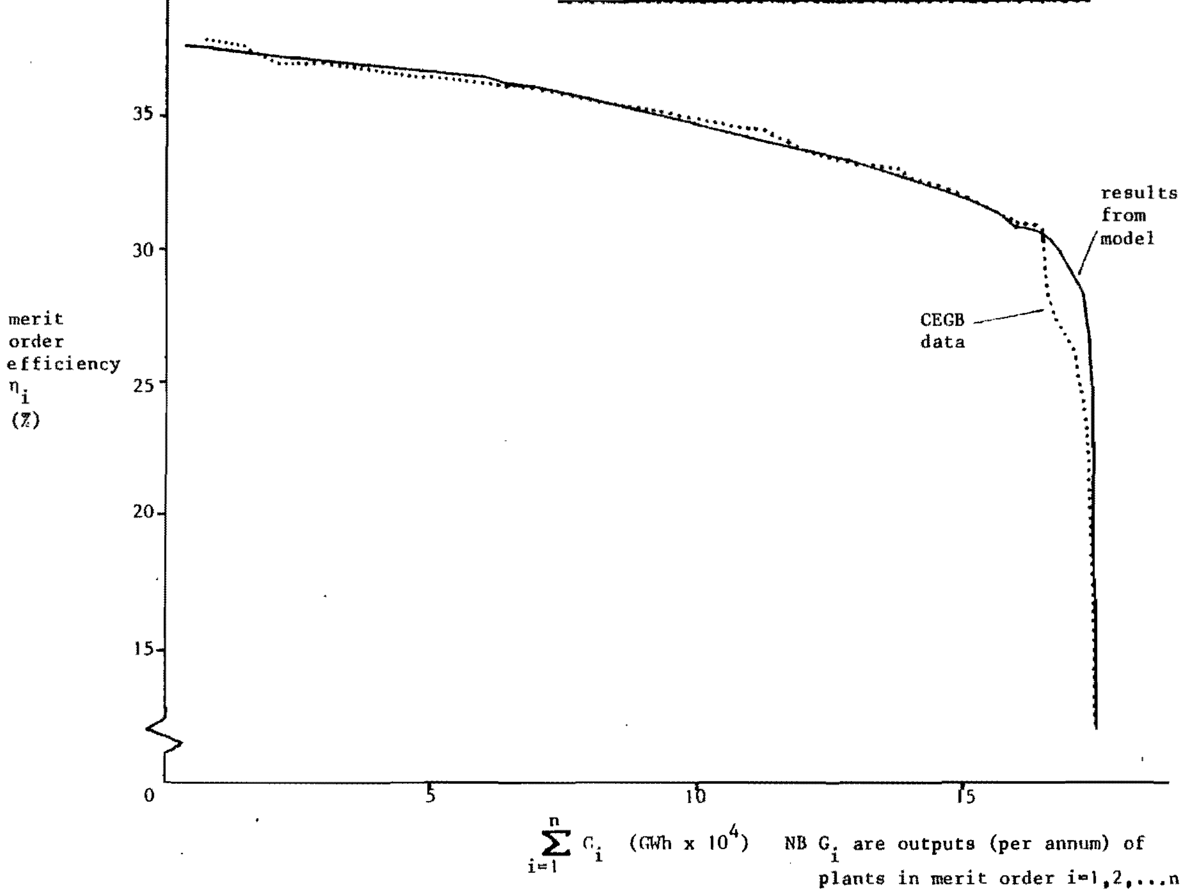
As will be apparent from the main text, stress has been placed on the fuel savings resulting from reduced starts and standby use of conventional plant when storage is used for load-levelling. The accuracy of the model's estimates of these benefits will depend crucially on the accuracy of the model's simulation of the merit order. Merit order, it may be recalled, was built into the model by assuming a particular range of full-load efficiencies which gave rise to an overall generation efficiency comparable to the CEGB's and for which the best units corresponded roughly with those on the CEGB system.

The standby and start up losses calculated in the model were arrived at after discussions with the CEGB and plant operators. Plant efficiencies appearing in the CEGB statistics are the overall efficiencies taking into account part-load operation and start-up and standby losses. Units low down the merit order can show very poor performance not just because they are intrinsically less efficient but because their operating routines (ie occasional use to meet peak loads) are not condusive to good overall performance. In order to compare these efficiencies with those generated by the model it is necessary to correct the model (full-load) efficiencies to take account of time on part-loading and start-up and standby fuel consumption. Sufficient output is provided by the model on the operation of the 85 assumed 500 MW units to enable these corrections to be calculated. One difficulty however still remains - the assumption in the model that units are 100% available while this is far from the case in any real generation system. Fortunately this problem can be avoided by comparing efficiencies for total electricity generated in merit order. Plant low down the merit order (ie with low overall efficiency) will only be used to generate a very small proportion of the total system output. If the total generated output is arranged in order corresponding to the merit order of the plant on which it was generated and plotted against the overall plant efficiency we should be in a position to make a comparison between the model and CEGB system.

Figure A1.3 shows this comparison of the model against CEGB non-nuclear steam plant efficiencies and actual generation for 1981-82, the year on which the plant efficiencies assumed in the model were based. (The x axis was renormalised for the 1981-82 CEGB data to take account of the difference between the total generated in that year and in 1978 - the load year used in the model).

The agreement is good. If anything the model overestimates efficiencies for plants low down the merit order indicating that start-up and standby losses may have been slightly underestimated. However, as mentioned in section A1.2, recent CEGB data[66] indicates the figure assumed in the model for no load fuel consumption to be slightly high which will tend to underestimate efficiency.* It is presumed that modelling assumptions with regard to standby and start up operation underestimate the associated fuel penalties and thus tend to overestimate overall efficiency. The trade off of these errors appears to provide a relatively good model of overall plant performance. A further difficulty associated with validation is that the model does not specifically include oil fired thermal plant.

Figure A1.3 : Merit order efficiency validation



For the year studied this is not a significant problem as the proportion of oil fired generation was low. Should this proportion increase the applicability of the model would have to be reassessed if it were to be used to assess future scenarios.

In conclusion it is fair to say that this one attempt at validation has been successful with the consequence that reasonable confidence can be placed in the results presented in Section 4 in particular those relating to the standby and start-up savings provided by storage.

Appendix 2 : Transmission losses from Dinorwig

Since the major proportion of the transmission network (supergrid) can be run at 400 kV (74% in 1982)[69] we will only concern ourselves with losses at this voltage. Total losses for ACSR ZEBRA transmission are given by 0.44 Ω per mile at a phase angle of $\theta = 86^{\circ}$.[70] Consequently the purely resistive losses are given by 0.0307 Ω per mile or $1.92 \times 10^{-2}\,\Omega$ per km.

Assuming a representative power factor of 0.9 for the complete supply system we have the total power flow given by

$$P = 0.9 \ V I$$

where V is the voltage and I the current. Losses per km are given by

$$L = I^2 R$$

$$= 1.92 \times 10^{-2} \ I^2$$

$$= \frac{1.92 \times 10^{-2} \times P^2}{(0.9 \times V)^2} \quad \text{watts/km}$$

At 400 kV we have

$$L = \frac{1.92 \times 10^{-2} \times P^2}{(0.9 \times 4 \times 10^5)^2} \quad \text{watts/km}$$

From CEGB data[68] we know that transmission losses amount to roughly 2.6% of net output. Assuming these to be entirely associated with cable losses we have on 'average'

$$\frac{1.92 \times 10^{-2} \times P^2}{(0.9 \times 4 \times 10^5)^2} \quad \times \quad D = 0.026 \times P$$

where D is the average transmission distance in km.

Thus

$$D = \frac{0.026 \times (0.9 \times 4 \times 10^5)^2}{1.92 \times 10^{-2} \times P} \quad \text{km} \qquad \text{(A2.1)}$$

Estimating P is more difficult. As we are interested in I^2 losses the appropriate 'average' value is the RMS. For 1978 the annual RMS hourly load was 25.9 GW. On the assumption that the transmission network is capable of supplying in total about 60 GW, the RMS corrected load factor is given by

$$25.9/60 = 0.432$$

The 400 KV Quad ZEBRA lines are now rated at 2480 MVA[25] (with a power factor of 0.9 this gives 2232 MW).

The RMS load on an average line can thus be estimated as

$$P = 0.432 \times 2232 = 963.5 \times 10^6 \text{ W}$$

Substituting into equation (A2.1) above gives:

$$D = \frac{0.026 \times (0.9 \times 4 \times 10^5)^2}{1.92 \times 10^{-2} \times 963.5 \times 10^6}$$

$$= 182 \text{ km}$$

If in fact only 60% of these losses are associated with the transmission lines the 'average' transmission distance is reduced to

$$D = 109 \text{ km}$$

with 1.04% (2.6 x 0.4) of the net output taking account of other transmission losses (transformers etc).

Transmission losses for Dinorwig can be calculated on the basis of the average transmission length to the major load centres of Greater London, the Midlands and the Manchester/Liverpool conurbation. This has been estimated at 350 km and thus transmission line losses from Dinorwig are

$$(350/109) \times 0.6 \times 0.026 = 0.05.$$

The total transmission system losses are thus

$$0.05 + 0.0104 = 0.06$$

ie 6% of the net output from Dinorwig.

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