THE MONOPOLIES AND MERGERS COMMISSION

Central Electricity Generating Board

A Report on the operation by the Board of its system for the generation and supply of electricity in bulk

Presented to Parliament in pursuance of Section 17 of the Competition Act 1980

Ordered by The House of Commons *to be printed*
20th May 1981

LONDON
HER MAJESTY'S STATIONERY OFFICE

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* These members formed the Group which was responsible for this Report (see paragraph 1.2).

Note by the Department of Trade

In accordance with sections 17(4) and 17(5) of the Competition Act 1980, the Secretary of State for Trade has excluded from the copies of the report as laid before Parliament, and as published, certain matters publication of which appears to the Secretary of State to be against the public interest or which are matters relating to the affairs of particular persons whose interests would, in his opinion, be seriously and prejudicially affected by publication and publication of which appears to him not to be in the public interest. Accordingly certain parts of the text and a table and certain figures in the text have been omitted. The omissions are indicated by a note in square brackets.

No exclusions have been made from Chapter 13, Conclusions.

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Glossary

kW	Kilowatt, unit of electrical demand or capacity to meet demand.
MW	Megawatt, one thousand kilowatts.
GW	Gigawatt, one million kilowatts.
MW so	Megawatts sent out, capacity less the quantity of electricity consumed in production.
kWh	Kilowatt hour, unit of electricity energy consumption; the commercial 'unit' of electricity.
TWh	Terawatt hour, one thousand million kilowatt hours.
kVA	Kilovolt ampere, unit of current rating
Hz	Hertz, unit of frequency in cycles per second.
GJ	Gigajoule, unit of heat energy (and mechanical and electrical energy).
mtce	Million tonnes of coal equivalent, the quantity of fuel which has the same calorific value as one million tonnes of coal.
ESI	The electricity supply industry in England and Wales, comprising the Electricity Council, the Central Electricity Generating Board and the 12 Area Boards.
SSEB	The South of Scotland Electricity Board.
EDF	Electricité de France.

CHAPTER 1

Introduction

1.1. On 3 June 1980 the Department of Trade sent to the Commission the following reference:

The Secretary of State, in exercise of his powers under section 11(1)(*a*) of the Competition Act 1980, hereby refers to the Monopolies and Mergers Commission the questions set out below relating to the efficiency and costs of the Central Electricity Generating Board in operating its system for the generation and supply of electricity in bulk.

The Commission shall upon this reference investigate and report on the question whether, in operating the said system, the Board could, without reducing the standard of service provided, improve its efficiency so as to be able to reduce its costs or mitigate the effect of any increases in its costs, with particular reference to:

(*a*) its internal cost control and project control systems,

(*b*) its management information systems,

(*c*) its purchasing policies and methods of stock control,

(*d*) its management of plant maintenance and the effect of programmes for plant maintenance on plant availability,

(*e*) the planning and appraisal of new investment, and its ability to carry out its proposals for such investment within the cost and the time estimated;

and on the question whether, in relation to any matter falling within the question set out above, the Board is pursuing a course of conduct which operates against the public interest.

The Commission shall report on this reference within a period of six months beginning with the date hereof.

3 June 1980

S G Linstead
An Assistant Secretary
Department of Trade

On 2 December 1980 the Secretary of State announced that he was satisfied that there were special reasons why our report could not be made within the time specified in the reference. Accordingly he decided to allow a further period to 2 March 1981 for the making of this report.

1.2. On 5 June 1980 the Chairman of the Commission, acting under Section 4 of the Fair Trading Act 1973 and paragraph 10 of Schedule 3 thereto, directed that the functions of the Commission in relation to this reference should be discharged through a group of five members with himself as chairman. An additional member of the group was appointed on 16 June 1980 pursuant to paragraph 13 of Schedule 3. The composition of the group is indicated in the list of members which prefaces this report.

1.3. The decision to refer the investigation to the Commission was announced by the Minister of State for Consumer Affairs on 12 May 1980. On 3 June 1980 a press notice was issued by the Department of Trade giving the full text of the terms of reference and advising any person or organisation wishing to offer evidence to write to the Secretary of the Commission.

1.4. In addition to the Central Electricity Generating Board and trade unions, specific invitations to submit evidence were sent to the Electricity Council, the 12 Area Boards, the Electricity Consumers' Council, the National Coal Board, British Rail, British Gas Corporation, British Nuclear Fuels Ltd, nine electric power utilities overseas, 11 trade associations, eight companies supplying fuel oil and 36 companies engaged in the supply of power station plant. Written evidence was received from 36 of these bodies, including statements from the Electrical Electronic Telecommunication and Plumbing Union and the Electrical Power Engineers' Association. The Employees' National Committee representing the unions in the industry had told us that it had decided not to submit evidence for this inquiry. However, the EETPU decided to send its own statement, and the EPEA also submitted evidence for the inquiry, when we specifically invited it to do so.

1.5. We received evidence at two hearings from the Chairman and Deputy Chairman of the Central Electricity Generating Board (the CEGB) and other Board Members and senior managers. Representatives of the National Coal Board, the Electricity Consumers' Council, the British Electrical and Allied Manufacturers' Association and of three subsidiaries of The General Electric Company Ltd (GEC Turbine Generators Ltd, GEC Power Engineering Ltd and GEC High Voltage Switchgear Ltd) also attended hearings and gave evidence. Meetings were held with a number of other companies engaged in power station construction.

1.6. Members of the Commission visited power stations, a nuclear power station under construction, the National Grid Control Centre, two Regional headquarters (one member visited four Regional headquarters) and the headquarers of the Generation Development and Construction Division (Barnwood). Officials made detailed enquiries at a number of power stations, Regional headquarters and at Barnwood.

Structure of the industry

1.7. It is necessary at this point to explain briefly that the electricity supply industry in England and Wales (the ESI) is divided into 14 statutory bodies, all reporting separately to the Secretary of State for Energy: the Electricity Council, 12 Area Boards and the Central Electricity Generating Board (CEGB). In terms of assets, income and capital expenditure, the CEGB represents the major part of the industry. In Scotland and Northern Ireland, independent Boards are responsible for electricity supply. The structure of the industry is discussed in greater detail in Chapter 2. It has affected our report in two ways:

(*a*) The Secretary of State announced on 14 July 1980 that he had decided not to accept the recommendation made in 1976 by the Plowden Committee in its report 'The structure of the Electricity Supply Industry in England and in Wales' (Cmnd 6388) that the industry should be unified into a single corporation. He will, however, look for improved co-operation and working relations between the various bodies which make up the industry, within the existing statutory framework. In view of the Secretary of State's decision, we have not said anything about the industry's structure. We hope however that means can be found of bringing the CEGB closer to the final consumer of electricity and more is said on this point in Chapter 4.

(*b*) The CEGB, except in one or two special cases (see Chapter 2), does not supply consumers direct but transmits electricity in bulk to the 12 Area Boards, who in turn distribute it to consumers. Except incidentally, it has not been our concern to look at the level and structure of prices charged to consumers of electricity. Prices charged by the CEGB to Area Boards are considered in Chapter 4.

1.8. We turn now to the scope of our report. Section 11 of the Competition Act requires the Commission to 'exclude from their investigation and report consideration of any question relating to the appropriateness of any financial obligations or guidance as to financial objectives (however expressed) imposed on or given to the person in question under any enactment, or otherwise by a Minister'. Nevertheless, in Chapter 3 we describe the financial targets and guidance given to the CEGB by the Secretary of State since they affect the CEGB's actions and performance. From time to time in the report we comment on the effects of these financial constraints. We also summarise below those targets and guidance, and how they affect each other:

(*a*) the CEGB's financial target set by the Secretary of State is an average return for the three-year period 1980–81 to 1982–83 of 1·8 per cent on net assets (excluding capital work-in-progress) calculated on a current cost accounting basis. (For information about the CEGB's adoption of current cost accounting, see below.) This target represents a higher return than the Board has achieved in recent years. The Government has accepted that the return in 1980–81 will be lower than the average for the three-year period. In consequence, higher returns will be needed in the following two years. The CEGB has said that price increases will be required, in addition to cost savings in order to reach its target. The Board expects to make a loss after interest, on a current cost accounting basis, in 1980–81.

(*b*) The financial target set by the Government assumes that the CEGB will adopt, as will most other nationalised industries, current cost accounting during the financial year 1980–81. The subject is discussed in greater detail in Chapter 3. One effect will be to increase unit costs, as a result of higher depreciation charges.

(*c*) The pressure applied by the financial targets has been supplemented by the imposition of cash limits (since 1979 called external financing limits—EFL), which fix a ceiling for borrowing within the year. The EFL can be a more stringent control than the financial target. The EFL is affected not only by the same factors as bear on the financial target—changes in revenue or operating costs—but also by the levels of working capital and capital expenditure. The EFL applies strictly to the year for which it is set; the financial target may allow some flexibility from year to year. In 1979–80 the CEGB's net borrowing requirement under the EFL originally given was £43 million; mainly because of increased working capital requirements, the EFL was subsequently varied to permit increased borrowing by the CEGB of £441 million. Capital expenditure was also reduced. Due to lower than expected demand for electricity, an increase has also beeen sought in the electricity supply industry's EFL of £187 million for 1980–81 and the CEGB's borrowing requirements within this total.

(*d*) Government guidance is also given to the Board on pricing. The CEGB's policy, endorsed by the Government, is to base prices on long-run marginal costs.

(*e*) Another important financial obligation of the CEGB is to contain capital expenditure in each financial year within the amount authorised by the Secretary of State. In addition, the Secretary of State approves each proposal to build major power stations or to embark on other large capital projects.

1.9. In our inquiry we have concentrated on the generation of electricity and the construction of power stations. These are the areas in the CEGB where the bulk of costs are incurred. We also discuss transmission, for example, in Chapters 6 (Operational Planning) and 11 (Management Information Systems). We have not, however, examined the Transmission and Technical Services Division or the Research Division (see paragraphs 2.24 and 2.25).

1.10. The following reports in recent years are among those which have commented on the affairs of the CEGB, either directly, or indirectly as part of an inquiry into other organisations:

(*a*) Report of the Committee of Inquiry into the Electricity Supply Industry (January 1956) (Cmnd 9672) ('the Herbert Report') (an inquiry into the organisation and efficiency of the electricity supply industry).

(*b*) Report by the Select Committee on Nationalised Industries on 'The Electricity Supply Industry', published in May 1963 (HC 236).

(*c*) Report No 59 of the National Board for Prices and Incomes entitled 'The Bulk Supply Tariff of the Central Electricity Generating Board' published in March 1968 (Cmnd 3575).

(*d*) Report by the Committee of Enquiry into Delays in Commissioning CEGB Power Stations (Cmnd 3960), published in March 1969 (the Wilson Report).

(*e*) The NEDO report on Large Industrial Sites (1970) (the 1970 NEDO report) and the NEDO report on Engineering Construction Performance (1976) (the 1976 NEDO report).

(*f*) A report entitled 'The Structure of the Electricity Supply Industry in England and Wales', published in January 1976 (Cmnd 6388) (the Plowden Report).

(*g*) Two reports by the Price Commission; entitled 'Fuel Cost Adjustment for the Supply of Electricity' (HC 133, January 1979) (the FCA report) and 'Area Electricity Boards—Electricity Prices and Certain Allied Charges' (HC 132 July 1979) (the Area Boards report).

1.11. During our investigation the House of Commons Select Committee on Energy continued its inquiry into the nuclear power programme announced in a statement by the Secretary of State in December 1979.

1.12. Some of the evidence obtained in the course of our inquiry was of a confidential nature; our report contains only such information as we consider necessary for understanding our conclusions.

1.13. The structure of the electricity supply industry in England and Wales and the organisation of the CEGB is explained in Chapter 2. The financial chapter (Chapter 3) concentrates on procedures for the control of both revenue and capital expenditure; it also discusses the financial framework within which the Board operates, including the adoption of current cost accounting. The planning of the CEGB's investment in new power stations for seven years ahead is assessed in Chapters 4 and 5; the main assumptions put forward in its investment appraisals and also the case for the nuclear programme are critically examined. Operational planning, as distinct from investment planning, the CEGB's other main planning function, is the subject of Chapter 6; we focus on how the Board plans to use its generating capacity to meet changing demand throughout the year at minimum cost. Fuel for power stations represents 60 per cent of the Board's costs; Chapter 7 comments on the purchasing and stocking of coal, oil and nuclear fuel. It is crucial to the CEGB's operating efficiency to maximise the time when its plant is available to produce electricity, particularly during the winter months, and to minimise loss of availability caused by planned maintenance or breakdown; these aspects of efficiency are discussed in Chapter 8. Availability and maintenance of generating plant are affected by efficient purchasing and stocking of spare parts for generating plant, both nationally and regionally; we consider this subject in Chapter 9. In Chapter 10 we examine the effectiveness of the Board's personnel and industrial relations policies in containing labour costs and making the most efficient use of the labour force. Chapter 11 reports on the high volume of management information, the computer facilities which support it and progress towards a central policy for management information. How the CEGB organises the building of its power stations is considered in Chapter 12; particular reference is made to matters not covered in extensive previous inquiries, such as the contractual arrangements now being devised for nuclear construction.

1.14. We should like to take this opportunity to thank all those who helped us in the course of our inquiry and we are particularly grateful to the representatives of the CEGB at all levels on whom our inquiry made considerable demands.

CHAPTER 2

The Electricity Supply Industry in England and Wales and the CEGB

2.1. In Chapter 1 we referred briefly to the divided structure of the industry. We now describe in outline the functions of the 14 statutory bodies in the industry, and in more detail the role and statutory duties of the CEGB. This is followed by an account of the CEGB's organisation and structure.

The ESI in outline

2.2. Since 1957, the industry in England and Wales has comprised the following statutory bodies:

(*a*) the CEGB, which is responsible for generation and transmission of electricity in bulk, through the high voltage power lines of its National Grid;

(*b*) the 12 Area Boards, which receive bulk supplies from the CEGB for distribution through their own networks to some 20 million industrial, commercial and domestic customers; and

(*c*) the Electricity Council, which is the forum where general policy of the ESI is discussed. The CEGB and the 12 Area Boards must consult the Council on certain matters, particularly on their capital investment programmes and tariff proposals. It has no powers to direct or control the 13 Boards, which discuss separately with the Secretary of State their own capital investment programmes. By agreement with the 13 Boards, it can speak on behalf of the industry.

In Scotland and Northern Ireland, electricity supply is the responsibility of boards, which are independent of the boards in England and Wales.

Consumer representation

2.3. In addition to the supply industry itself, there are 13 organisations which represent the interests of electricity consumers in England and Wales. The Electricity Consumers' Council (the ECC), a non-statutory organisation set up in 1977, represents consumers at national level. Twelve Area Electricity Consultative Councils, established by the Electricity Act 1947, one for the area of each Area Board, represent consumers' interests locally.

The CEGB's functions and position in the industry

2.4. The CEGB owns and operates the power stations which generate electricity, and the National Grid through which it supplies electricity in bulk to the Area Boards. At 31 March 1980 the Board's system comprised 132 power stations with a declared net capability of some 57,000 MW. The National Grid network comprises about 7,800 kilometres of main transmission lines (400 and 275 kV)—the largest unified system in the western world.

2.5. The disposition of the largest power stations is shown in Appendix 1.

Statutory duties of CEGB

2.6. The CEGB was created by the Electricity Act 1957. Under that Act many of the functions and duties of the Central Electricity Authority were taken over by the CEGB and the Electricity Council. The Board's main duty is to develop and maintain an efficient, co-ordinated and economical system of supply of electricity in bulk for all parts of England and Wales and for that purpose to generate or acquire electricity and provide bulk supplies to Area Boards for distribution to consumers. The Board exchanges bulk supplies of electricity with the South of Scotland Electricity Board, and Electricité de France. With the authority of the Secretary of State, it supplies electricity directly to some consumers: the United Kingdom Atomic Energy Authority (from which it also purchases electricity) and Anglesey Aluminium Metal Ltd are supplied in this way. Supplies of electricity are also exchanged with British Nuclear Fuels Ltd (a wholly-owned subsidiary of UKAEA, which provides fuel services for nuclear power stations in the United Kingdom and to overseas customers; see Chapter 7). The CEGB also has a statutory duty to supply the electricity requirements of British Rail and London Transport. In formulating proposals relating to its functions, the Board must take into account their effect on the amenities of the countryside. The Board must balance revenue and outgoings, taking one year with another. It must fix its tariff, after consulting the Electricity Council, and, also after consulting the Council, obtain the Secretary of State's approval of its programmes of capital expenditure. (The tariff and capital expenditure programmes are discussed in Chapters 4 and 5.)

Area Boards—generation of electricity

2.7. Since 1957 the Area Boards have also had statutory power to generate electricity; before doing so, they must consult the CEGB and the Electricity Council and obtain the Secretary of State's approval. Up to now this power has only rarely been used.

The Electricity Council's role

2.8. The Electricity Council's role in the industry affects both the way in which the CEGB functions and the Board's relations with its main customers, the 12 Area Boards. Like the CEGB, the Electricity Council was brought into being by statute in 1957. Its two main statutory duties are to advise the Secretary of State on questions affecting the ESI and matters relating thereto; and to promote and assist the maintenance and development by the 12 Area Boards and the CEGB of an efficient, co-ordinated and economical system of electricity supply. It will be noted that these duties require only advice and assistance from the Council; it has no powers to direct or control the Area Boards or the CEGB, each of which remains responsible to the Secretary of State for its own affairs and performance. This point is underlined by the Council's composition and its remaining functions. The membership of the Council consists of:

(i) the chairmen of the 12 Area Boards;

(ii) three members of the CEGB (the CEGB's Chairman and two other members of the Board, nominated by it); and

(iii) the Chairman and two Deputy chairmen of the Council and up to three other members directly appointed to these positions by the Secretary of State, not being themselves members of any of the 13 Electricity Boards.

2.9. The Council has the statutory right to be consulted by the Area Boards and the CEGB on their capital investment programmes and tariffs. However, the Council's approval of these matters is not required.

2.10. The specific statutory responsibilities of the Council include setting up and maintaining the machinery for negotiating terms and conditions of employment in the electricity supply industry; arranging finance for the industry; ensuring that suitable arrangements exist for the promotion of safety, health, welfare, education and training in the industry; setting up, in consultation with the Secretary of State, a programme of research into matters affecting electricity supply and affecting the functions of the Boards and ensuring that the research programme is carried out; and preparing annual reports and accounts covering the whole industry. In addition, the Council may with the agreement of any of the Boards, carry out common services or act on their behalf; public relations, and economic and market research are examples of many functions it performs on this basis.

2.11. The CEGB is much the largest single body in the industry and constitutes the major part of it. According to 'The Times 1000' 1979–80 review of leading companies in Britain and overseas, in terms of turnover and capital employed the CEGB ranked sixth among the largest companies and nationalised industries in the United Kingdom.

2.12. The following table analyses the CEGB's costs in 1979–80:

TABLE 2.1 **The CEGB's costs in 1979–80**

Expenditure	*p/kWh*	£ *million*	%
Fuel (including purchases of electricity)	1·343	2,936	61·9
Depreciation and interest	0·352	771	16·2
Salaries etc	0·216	471	10·0
Other materials, goods and services	0·201	439	9·3
Rents, rates and insurances	0·056	123	2·6
Total	2·168	4,740	100

Source: The CEGB.

In 1979–80 fuel thus represented about 62 per cent of the Board's costs, and capital charges (depreciation and interest) a further 16 per cent. In the same year, the average price of electricity sold to consumers by the Area Boards and the CEGB was 2·804 pence per kilowatt hour.

British Electricity International Ltd

2.13. Expertise acquired by the CEGB in designing and operating power stations and transmission systems is made available on a consultancy basis to electricity utilities overseas. During the year to 31 March 1980, 150 of Board's staff worked overseas as consultants in 30 countries in support of the export activities of British manufacturers of power plant and transmission equipment. These services are provided through British Electricity International Ltd (BEI), a wholly-owned subsidiary of the Electricity Council. BEI markets services available from the electricity supply industry in Great Britain and Northern Ireland and not merely the CEGB. Of its 300 staff working on assignments overseas in March 1980, half were made available by the CEGB, and the remainder by Area Boards in England and Wales and the Electricity Boards in Scotland and Northern Ireland. The turnover of BEI in 1979–80 was some £8 million.

Organisation and structure of the CEGB

2.14. We were told that, in performing its statutory duties (under the Electricity Acts of 1947 and 1957), the CEGB sees itself engaging in two main activities:

(*a*) the planning, development and construction of the system of generating stations, transmission lines and sub-stations; and

(*b*) the operation of the system in a secure and efficient manner so that demand is met at minimum cost.

2.15. Final responsibility for the discharge of the CEGB's statutory functions rests with the Board which currently comprises the Chairman, Deputy Chairman and three other full-time members, each with individual areas of responsibilities according to his particular expertise. There are also three part-time members. For the purpose of the day-to-day running of the CEGB, the Board has authorised full-time members, acting collectively as the Executive, to take such action as it deems necessary between Board meetings to secure the achievement of the Board's objectives.

2.16. The Board told us that it is its policy to maximise the delegation of authority from the Board to its senior managers, who are personally accountable to the Executive, and this delegation and personal accountability is extended further down the line. Accordingly, the Board carries out from the centre only those matters which cannot satisfactorily be delegated to operating units or where there is a commercial advantage to be obtained. At the same time, the Executive, supported by Chief Officers and specific corporate machinery, provides a strong integrating force.

2.17. In accordance with the Board's management policy, the Executive delegates authority to Directors General of Regions (see paragraphs 2.21–2.22) and Divisions (see paragraphs 2.23–2.25) and to Headquarters Chief Officers (see paragraph 2.19). They, individually, are accountable to the Executive for their responsibilities and within their particular remit, are the source of all Executive action.

2.18. Additional to its responsibilities for the day-to-day running of the CEGB's activities, the Executive has certain powers specifically reserved to it. These include:

(*a*) consideration, prior to submission to the Board, of all Annual Plans and Regional, Divisional and Departmental operating policies, plans and budgets. This includes major changes in Regional, Divisional or Headquarters' Departmental organisational structures;

(*b*) consideration, prior to submission to the Board, of proposals for the Bulk Supply Tariff;

(*c*) consideration, prior to submission to the Board, of proposals on fuel policy having national implications;

(*d*) consideration, prior to submission to the Board, of proposals relating to financial policy, financial estimates and annual accounts;

(*e*) financial sanctions except to the extent delegated; and

(*f*) approval of tender and other contract matters except to the extent delegated.

2.19. Headquarters Chief Officers and their Departments are expected to contribute policy recommendations to the Board's Executive, to exercise functional direction over other parts of the Board's organisation and to provide a service where an activity can be better dealt with centrally than in dispersed units. Each Chief Officer has the right to be consulted by Directors General (Regional or Divisional) on any matter of significance within his functional interest. Conversely, each is responsible to the Executive for practices carried out within his function. There are currently seven Chief Officers at Headquarters comprising six Directors responsible respectively for Operations, Planning, Finance, Personnel, Computing, and Health and Safety, and the Board's Secretary.

2.20. In the systems operations field the CEGB has two major functions: the generation of electricity and its transmission to the points at which it passes into the distribution systems of Area Boards. In order to fulfil these functions a Regional organisation has been established under which the CEGB's territory has been divided into five Regions (the South Eastern, the South Western, the Midlands, the North Eastern and the North Western Regions) each with its own headquarters and each entrusted with the maintenance and operation of the power stations and transmission systems within its boundaries. Additionally, the specific task of grid control is entrusted to seven grid control centres (the South Eastern and Midlands Regions have two such centres, the other Regions each have one). Grid control centres are responsible to, and controlled by, the National Control Centre in London which ensures that the power system operates efficiently and securely as an integrated whole by arranging in advance power transfers between the seven grid control Areas: these transfers it monitors and adjusts continuously so that the most economical plant available at any time is used to supply the national demand for electricity.

2.21. Each Region is under the control of a Director General, to whom report a number of Directors and Departmental heads with responsibility in specific areas. Each Region has Directors responsible for production, for engineering and for resource planning: Departmental heads cover such service functions as finance, personnel, secretarial and scientific services. Power stations are organised in groups under Group Managers (who are on the staff of the Regional Director of Production) but each station manager reports directly to the Regional Director of Production.

2.22. In addition to the Regional organisation there are three Divisions, each headed by a Director General, two of which have overall responsibility throughout the Board's business for one of the CEGB's main activities—the planning, development and construction of generating plant and of the transmission system.

2.23. The Generation Development and Construction Division (Barnwood), previously at four separate locations, was brought together at Barnwood (near Gloucester) in 1974. The Director General is supported by Directors responsible for projects, for station design, for plant engineering and for associated commercial matters. Total employment is about 2,000. The functions of Barnwood are dealt with fully in Chapter 12 (particularly paragraphs 12.1 to 12.6 and Appendix 24).

2.24. The Transmission and Technical Services Division (TTSD) is located at Guildford. This Division has three main functions—the design of transmission systems, their construction, and engineering services—each of which is under the control of a Director supported by Commercial, Administration and Personnel Departments. A substantial part of the present TTSD was formed in 1971 by the merging of the Transmissions Project Group (located at Guildford since 1961), with the Transmission development and Design Branch (formerly located in CEGB Headquarters, London): this was known as the Transmission Development and Construction Division (TDCD). In September 1979 Engineering Services—the objective of which was the delivery and completion of plant and equipment on time and to the appropriate quality, and which maintained a number of Field Officers located in industrial centres—was merged with the TDCD to form the TTSD. Total employment in TTSD is 1,200.

2.25. The third Division (the Research Division) is responsible for research. It employs about 2,000 people at Leatherhead, Marchwood and Berkeley. Much of the Division's work is currently concerned with the efficiency and availability of Magnox and AGR reactors. In 1979–80, current expenditure of the Division excluding capital charges was £48 million.

2.26. As explained in Chapter 1, we have not examined either TTSD or the Research Division.

2.27. The chart at Appendix 2 illustrates the CEGB organisation.

CHAPTER 3

Financial framework

3.1. In Chapter 1, we referred to the financial constraints imposed by Government upon the ESI, only one of which is directly applicable to the CEGB. This is the requirement laid upon the Board to obtain the approval of the Secretary of State for Energy for its capital investment programme for each year and his specific approval before placing an order for a new power station.

3.2. The other two financial constraints imposed upon the ESI currently comprise:

(i) a financial target, which is an average return, before charging interest, for the three year period 1980–81 to 1982–83 of 1·8 per cent on net assets (excluding capital work-in-progress), calculated on a current cost accounting basis. The Secretary of State for Energy has indicated that he expects the return in 1980–81 to be below the average set for the three year period and that the returns for 1981–82 and 1982–83 will be correspondingly higher;

(ii) an external financing limit (EFL), set for the ESI as a whole and within which the Board's transactions have to be contained. The EFL has been set at £187 million for the financial year 1980–81. In the financial year 1981–82, however, rather than be permitted to raise additional external finance, the ESI is required to make a net repayment of £210 million.

3.3. The ESI comprises the CEGB and the Area Boards, all independent bodies, and the Electricity Council, which co-ordinates the activities of the Boards and is responsible for planning the achievement of the financial target and the observation of the EFL. The Board and the Area Boards are represented on the Electricity Council. The CEGB, which owns the power stations and the transmission system, possesses the great bulk of the industry's fixed assets. This fact, coupled with its being the supplier, in the first instance, of the industry's product, makes the activities of the Board central to the plans of the Electricity Council. These plans currently include a financial target for the Board equal to that set for the industry as a whole.

Adoption of current cost accounting

3.4. It will be noted that the present financial target is calculated on a current cost accounting (CCA) basis. Before considering the effect of the current financial target, we discuss the impact upon the Board's accounts for 1980–81 of adopting this accounting convention, together with other changes in accounting practice. The form of the Board's accounts, and the basis of calculation of its costs, will in future comply with the provisions of the Statement of Standard Accounting Practice on current cost accounting (SSAP 16). Under this standard the gearing adjustment does not apply to nationalised industries, but monetary working capital adjustments (MWCAs) will be incorporated in the results. Changes in accounting practice are necessary in order to eliminate certain aspects of the policy adopted by the Board, in the preparation of historical cost accounts, in its attempt to produce as realistic a charge for depreciation as possible in times of inflation. These comprised:

(i) charge for depreciation on capital work-in-progress;

(ii) conscious choice of asset lives at the shorter-end of the assessed range of life for each class of assets; and

(iii) provision for supplementary depreciation at the rate of 40 per cent of the historic cost depreciation charge.

3.5. Valuation on a CCA basis of the assets employed in producing the Board's income means that depreciation, calculated on a more conventional basis than previously adopted under the historical cost convention (HCA) will realistically reflect the consumption of these assets and make adequate provision for their future replacement. For these reasons, the CCA accounts will include neither depreciation of capital work in progress (thus conforming with SSAP 12) nor a charge for supplementary depreciation. Further, asset lives will be more realistically assessed. The scale of extension of asset lives is indicated by the following table:

	HCA lives in years	*CCA lives in years*
Conventional steam stations	25	30–40
Nuclear stations	20	25
Transmission assets	30	40

3.6. In its Annual Report and Accounts for 1979–80 (paragraph 2.16 and Table 25) the Board stated that, on the assumption of a requirement upon it of 226 TWh (equivalent to sales of 220·8 TWh) and with fossil fuel prices at March 1980 levels, costs per kWh for 1980–81 were estimated to exceed the actual costs in 1979–80 by some 30 per cent, of which a little under half would derive from the adoption of CCA.

The current financial target

3.7. Under the provisions of section 11 of the Competition Act 1980, we are precluded from considering the appropriateness of the financial obligations or guidance as to financial objectives imposed on or given to the ESI or the Board. It is, however, both proper and necessary for us to examine the effect of these constraints on the Board's policies and the extent to which they act as a constraint on the Board in the management of its business.

3.8. The Board has told us that the previous financial target of 9·8 per cent on average net assets calculated in HCA terms, would, in 1979–80, have been equivalent to a CCA return, calculated on the same basis as the current target, of between 1 and 1·5 per cent. The latest target of 1·8 per cent on a CCA basis continues the pattern of increase in the target return which has developed over the past 20 years.

3.9. An estimate of the Board's likely results for 1980–81, made, on a CCA basis, in early January 1981, indicates an increase in costs per kWh sold, on a reduced estimate of 212·1 TWh sold, of the order of 30·5 per cent over the 1979–80 costs established on an HCA basis. The forecast shows an increase in the average charge for electricity sold of about 25·7 per cent and a return, calculated on the same basis as the financial target, of approximately 0·9 per cent, or only half the target rate of return. These figures indicate that the full impact of the financial target upon prices has been postponed by planning its achievement over the three-year period. It will be noted that estimated sales of 212·1 TWh are some 4 per cent below the 220·8 TWh estimated for 1980–81 at the time the Board published its 1979–80 Report and Accounts in June 1980 (see paragraph 3.6 above). Contemporary forecasts for 1981–82 and 1982–83, based upon sales of 214·1 and 216 TWh respectively, indicate returns in these years of between 1·5 and 1·6 per cent. The forecasts show that achievement of these returns is expected to require year on year increases in the average charge for electricity sold of 16·7 per cent and 12·3 per cent respectively. The present trend of decline in national industrial activity is such that even these very recent estimates, including that for 1980–81, are under critical review lest they may prove to be over-optimistic. The forecasts referred to above are set out in Appendix 3.

3.10. In later paragraphs of this chapter we refer to the Board's 'cost minimisation' policy and its plans for staff reductions. The benefits of these policies, expected to accrue within the period of the current financial target, have been taken into account in the estimates referred to in paragraph 3.9 above.

3.11. Under these circumstances, we considered various other options which might be available to the Board in planning to attain the current financial target. One such option would be to reduce the net asset base upon which the return is calculated, by accelerating the programme of disposal of surplus fixed assets and possible reductions in the levels of fuel stocks and stores holdings. Even if it were practicable, an average reduction of (say) £50 million over the period would contribute less than £3 million towards the forecast shortfall of £254 million. We also considered whether the Board, by lowering or making other adjustments to the BST, could stimulate demand sufficiently to reduce the adverse margin between unit costs and the average charge for electricity sold, and thus make a contribution towards the achievement of the financial target. However, as a result of the structure of the ESI, the CEGB, with practically all its sales (98 per cent in 1979–80) being made to Area Boards, is not a marketing organisation and is virtually insulated from the consumer. We do not see the Board deriving any material benefit, towards achievement of the current financial target, from any adjustment it can make to the BST, other than to increase prices by margins greater than indicated in the current forecasts referred to in paragraph 3.9.

External financing limit and control of investment

3.12. The level at which the EFL is set strongly influences the level of borrowing from the Electricity Council available to the CEGB. The Board's investment programme, for which it requires the sanction of the Secretary of State for Energy, together with its working capital requirements, must be accommodated within the total of internally generated funds and the proportion of the EFL for the ESI as a whole allocated to the CEGB. Whilst there must be interaction between the level of EFL and the amount of investment sanctioned the EFL can be a severe constraint in times of financial stringency. In December 1979, the Secretary of State for Energy approved a capital allocation of £625 million at March 1979 prices. Given the anticipated level of price escalation from March 1979, this was equivalent to an expenditure in 1980–81 of £770 million. Subsequently the Board, under pressure from the EFL and because of the lower growth forecast, reduced its programme to £670 million (£543 million at March 1979 prices). Thus, the level of the EFL conflicted with the level of investment planned by the Board and authorised by Government. The Board is left with the choice of increasing prices in order to provide additional funds to pay for cost-saving investment or deferring the benefit it sees to be derived from such investment. In the absence of an adequate level of cost-saving new investment, it can continue to meet anticipated demand from existing, but less cost-effective, stations, with consequent higher operating costs and, therefore, higher prices.

Guidance on pricing policy

3.13. In addition to the imposition of financial constraints, the Government also gives guidance to the ESI on pricing policy, sometimes specifically in respect of the tariffs of Area Boards. In addition there is the general guidance to nationalised industries, contained in Cmnd 7131, that prices should generally reflect long-run marginal costs, using, where appropriate, the 5 per cent RRR (required rate of return) to reflect the capital element. It is the CEGB's policy to base prices on long-run marginal costs, but, because of various constraints placed upon price increases during the 1970s, the Board's prices have not in the past reflected such costs in full. During the course of our inquiry the Board told us that a recent calculation indicated that the current BST did now reflect their interpretation of long-run marginal costs. (See Chapter 4, paragraphs 4.66 and 4.67).

Longer-term prospects

3.14. The Board has attempted, with all due caution, to look at possible movements of its costs to the end of the century, although such long-term predictions are fraught with uncertainty. On present trends and present assumptions about plant costs, the Board foresees that its unit costs are likely to continue to rise in real terms until the mid-1990s. This is mainly because of rising fuel costs but also because the high level of investment in nuclear power foreseen for the 1990s will add substantially to the interest burden. It is expected that average costs will reach a peak between 3·5p/kWh and 3·7p/kWh (at 1980 prices) in the mid-1990s. Thereafter, with the benefits of an increasing contribution from nuclear power, they should begin slowly to decline. Without such a contribution average costs would continue to rise. On the Board's present estimates, a bulk supply tariff based on long-run marginal costs would appear not to yield enough revenue to cover the Board's costs, including interest, over the period up to the mid-1990s. The Board has told us that in making these forecasts it has been particularly conscious both that changes in the anticipated rate of demand growth may affect the position seriously, and that 60 per cent of its costs represent fuel costs, over which it has little control.

Internal cost control

3.15. In the following paragraphs we concentrate upon the Board's systems relating to the sanction of expenditure and the financial control of costs. We deal first with budget-setting and the monitoring of revenue expenditure against such budgets. Secondly, we consider various aspects of 'good housekeeping', including cash management and internal audit. Thirdly, we deal with financial control of capital projects, including both the cost control of projects and related contracts and the control of annual capital expenditure against the relevant budget.

3.16. The managerial structure of the Board shows that the governing bodies are The Generating Board and its Executive. Beneath these are the major budget centres which reflect the regional nature of the generating operations. These are supported by the essential services provided by other divisions and Board headquarters departments. The major budget centres are:

Regions (5)	South Eastern South Western Midlands North Eastern North Western
Divisions (3)	Generation Development and Construction Transmission and Technical Services Research
Headquarters Departments (7)	Computing Finance Health and Safety Operations Personnel Management Planning Secretary

3.17. Because the Board's revenues cannot be identified directly with particular stations, divisions, regions or HQ departments, none of these budget centres can be used as profit centres for financial control purposes. Instead, each unit is identified as a cost centre and submits separate budgets for its capital and revenue expenditure and its manpower levels, which are aggregated at different levels of management control.

3.18. Each of the regions and divisions is under the executive control of a Director General, while Directors head six of the headquarters departments, the other being headed by the Secretary. Emphasis is placed upon delegated authority coupled with accountability. Delegations of authority and accountability are set out in detail in the Board's Directive on Organisation and Management and clearly define the limitation placed upon the power to approve spending, including commitment to spend, in relation to each grade and function of officer. The Board's Directive on Financial Control sets the pattern for budget-setting, monitoring and reporting for both revenue and capital expenditure and applies throughout the operating regions, divisions and HQ departments.

3.19. The purpose of our review of these procedures was twofold. First, we wished to satisfy ourselves that the laid down procedures were being followed in practice. Secondly, we needed to establish the relevance of these procedures to the control and containment of cost. It is not our purpose, in this chapter, to comment upon the efficiency of the Board's use of resources.

3.20. In paragraphs 3.20 to 3.42 we deal first with budgetary control of revenue expenditure and in paragraphs 3.60 to 3.85 with control of capital expenditure. In both cases our review is based upon relevant budgets and monitoring returns produced over a period of years, reinforced by discussion of these documents and the laid-down procedures, with officers at headquarters, regional, divisional and station level. Our terms of reference being particularly directed to costs, we have confined our review in this chapter to this aspect of the Board's finances.

Budgetary control—revenue expenditure

3.21. It is important to realise that the budget procedures are part of a continuous cycle. A vital part is played by the production in the September of each year of the September Outline Plan (SOP) which forms the main planning instrument of the Board. This plan is formulated in the light of the annual 'Executive Guidance', a document published internally in late April or early May that sets out the corporate planning objectives of the CEGB in the short-term. The annual revenue expenditure budgetary cycle is summarised below. (The Board's financial year runs to 31 March.)

April The Executive issues formal policy guidance to major budget centres to provide a framework for preparation of management plans for the next five years. The Executive Guidance includes targets for cost reduction, commissioning of new plant, plant performance and consideration of how the various targets can be achieved. For some years the CEGB has had an internally set overall long-term objective of holding the rise in its unit costs down to the level of general inflation in the economy. Against this long-term objective, each year's 'Executive Guidance' is adapted to recognise the specific short-term circumstances of the moment. Executive guidance is backed by functional guidance from central finance, operation, personnel and planning departments.

May/June The Executive discusses the previous year's actual results against budget for the Board as a whole, which action is followed by discussion with each Director General of individual results, the current trend of operations and future prospects and as far as possible, the guidance to be included in the next five-year plan. Particular attention will be given to the key objectives which are relevant to the effective management of each location (ie regions, divisions, stations, departments and so on).

August/October Each major budget centre prepares its five-year plan. A national plan, the SOP, is produced which summarises cost predictions and this is reviewed against the Board's long-term cost minimisation objectives. The national plan identifies for the Executive the major issues thrown up by local plans on which discussions take place between the Executive, Directors General and Chief Officers.

October The SOP cost estimates, following modification by the Executive, form the basis of the following year's Bulk Supply Tariff (BST).

October The Executive issues policy instructions to budget centres to enable them to produce firm revenue expenditure budgets for the next financial year and provisional budgets for the following year.

December/January The Director of Finance discusses budgets with Directors General and Chief Officers before consolidating them and presenting an overall report to the Executive. The report of the Director of Finance reconciles the budgets for the following year with firm BST estimates for that year.

February Members of the Executive discuss each budget submission separately with Directors General and Chief Officers with special reference to explanations for changes in estimates for the coming year from those contained in the five-year plan. Further instructions are given together with any modified general instructions in the light of the current performance against budget and the financial outlook at the time.

March Modified budgets are re-examined by the Executive and if considered acceptable are put to the Board for approval. Thus, those figures which started as the initial year's forecast in the five-year plan are gradually refined to the point where they become the recommendation to the Board for approval as next year's budget. The process is continued by the cycle starting again with the second year's forecast in the preceding five-year plan being promoted to become, essentially, the initial year in the next SOP.

Special features of the revenue expenditure budget control system

SUPPLEMENTING AND FLEXING

3.22. For practical purposes, generating budgets comprise three main sections, that is to say fuel, payroll and associated costs, and other materials, goods and services (OMGS). Because of the significance of the figures relating to fuel and payroll costs, and in order to facilitate the preparation and approval of budgets within a practical timescale, these items are included at prices and rates ruling in the November preceding the budget year. During the course of the year, the budgets will be supplemented to reflect the effect of:

(i) changes in the levels of fuel prices from the base date prices; and

(ii) the results of the national pay negotiations (conducted by the Electricity Council on behalf of the industry with the various unions representing the employees), which are not known at the date of setting the budget.

3.23. In the case of fuel, a further adjustment is necessary. The budgeted cost of fuel for the Board is based upon an expected level of demand which is allocated to individual stations on the basis of their forecast availability (at any one time a certain number of stations will be on overhaul and therefore not available to generate) and their position in the order of merit. (The 'merit order' and its application are discussed in Chapter 6, paragraphs 6.15 to 6.18.) During the course of a financial year the actual loading on a station will differ from budget by virtue of both changes in national demand and plant breakdown. In order to adjust budgets for load changes on individual stations for whatever reason, and in order to authorise expenditure on fuel at a different level from that originally budgeted, the fuel budget is 'flexed' to give a budgeted fuel cost which is derived from the actual load taken by the station and budgeted levels of plant performance. The resulting comparison of actual fuel cost against flexed budget identifies both changes due to thermal efficiency and savings made in the purchasing of fuel.

3.24. Whilst 'flexing' may appear at first sight to be a device to make budgets easier to attain, it is, in practice, essential in order to make possible a valid judgment between budgets and actual results. This is because fuel currently accounts for over 60 per cent of total revenue costs and the amount consumed varies directly with output. The relationship between fuel costs and total revenue costs over the five years to March 1980 is illustrated in Table 3.1 below.

TABLE 3.1 **Fuel costs and total revenue costs 1975–76 to 1978–79**

	1975–76 £m	*1976–77* £m	*1977–78* £m	*1978–79* £m	*1979–80* £m
(i) Fuel and associated transport costs*	1,515	1,799	2,141	2,412	2,936
(ii) Total revenue costs	2,604	2,972	3,527	3,981	4,740
	%	%	%	%	%
Line (i) as % of line (ii)	58·2	60·5	60·7	60·6	61·9

Source: CEGB published accounts

* Includes purchases of electricity and interchange of supplies.

3.25. The remaining revenue expenditure is referred to as OMGS and is budgeted to include the forecast effect of changes in prices in the coming year. To assist in the preparation of budgets, guidance is provided by the Electricity Council on the forecast rate of inflation; we have been told that their estimates are normally on the low side. The OMGS budget is neither supplemented nor flexed during the year and budget-holders are expected to keep within the limits set in the original approved budget.

3.26. When questioned about the stringency of budget-setting, the Board told us that the principal pressure is brought to bear by the constant policy of holding down unit costs. Regions have made substantial reductions in their OMGS expenditure budgets for the current year and further reductions are planned for 1981–82. Since late 1978 there has been an increasing emphasis on reducing the numbers employed at all headquarters locations. In this connection, the current target is to reduce the number in post at 31 March 1980 by at least 5 per cent over the succeeding two years. Recently, it has been reported that the Board is seeking an overall reduction of 3,000 (about 5 per cent) in its total workforce 'as soon as possible', consistent with its rundown of some of the older stations. In the light of the fall in demand, the decommissioning programme has been accelerated, in order to secure general reductions in station costs.

3.27. Cost information, comprising results against budgets to date and forecast actual performance (outturn) for year against budget, is supplied on a regular basis from stations to regions and from the regions and divisions to headquarters. Such information is combined with the results of the headquarters departments to give the overall periodic results of the Board. Explanations of variances are supplied and examined at local, regional and national level. Commitments, in respect of expenditure which will be invoiced to the Board during the budget year, are likewise monitored on a cumulative basis against budget. The Board regards this control on commitments, exercised at all levels of management, as extremely significant.

3.28. Monitoring returns are submitted monthly to headquarters but the formal presentation, containing a commentary on the results and explanations of variances, is made to the Executive every quarter. Monthly returns submitted to headquarters are available to Executive members and are considered by them more frequently than is implied by the formal system. In the closing three months of the financial year, the latest results against budgets are examined monthly by the Executive. In addition to the presentation of results, the Executive meet the respective Directors General of the regions and divisions, on a bi-monthly basis, to discuss performance to date, ask supplementary questions about the reasons for deviation from budget and consider the latest forecasts of results for the year.

3.29. In order to satisfy ourselves that the laid down system of financial control is followed in the regions and is relevant to their needs, we visited Midlands Region (MR) and the South Eastern Region (SER), where we discussed budget setting and reporting procedures with the financial controllers and other officers at headquarters and station level. The following paragraphs, whilst relating to MR, are illustrative of the system in operation thoughout the regions, subject to some minor modifications to accommodate differences in local circumstances.

MIDLANDS REGION

3.30. The MR budget is an aggregation of the budgets for 28 power stations, four transmission districts and seven regional headquarters departments. Likewise, these latter budgets are aggregations of the budgets of lower formations. For example, a power station may be organised into five or more departments, whilst the seven headquarters departments collectively could comprise some 30 branches of activity. An organisation chart, showing the division of activities in Midlands Region, is at Appendix 4.

3.31 We were told that, in or about July, the Director of Resource Planning, together with the region's other directors and chief officers, including the Financial Controller, visits all the power stations and transmission districts in the region. The purpose of these visits is to discuss with local management the location plans, to explore options and to take decisions to ensure that location plans are in accordance with Executive and regional guidance. In this way expertise from regional headquarters is used to validate the economic viability of individual location proposals and to co-ordinate these so that, in total, location plans reflect the best strategy for the Board.

3.32. It was emphasised that the cost control system was composed of various facets, each of which made an important contribution to the overall objective, and it would be wrong to attach an overriding importance to any one aspect of control. Forecasting, management commitment to targets, monitoring of performance and post audit all had their part to play. Budgets are controlled in three separate ways:

(i) By resource —fuel, salaries, materials, goods and services;

(ii) By activity —mechanical, electrical and instrument maintenance departments, operations and technical and development office;

(iii) By job costing —major items of expenditure constitute, in total, about half a region's materials, goods and services and are individually identified and rigorously controlled through scheme appraisal, full budgetary control, final cost reporting and post appraisal.

3.33. The MR Director General is responsible in budgetary terms for the performance of his region as measured by all three methods of control, or 'disciplines'. The individual station manager is likewise responsible for the performance against budget of his power station as measured by the three disciplines. The section heads at a station are in turn responsible for the results of their department in conformity with discipline (ii) above, and a designated officer has to account for the recorded costs of jobs under discipline (iii), which will be listed for each piece of work expected to cost over a minimum sum (from £2,000 to £10,000 depending on the size of the station).

3.34. This system recognises that a region operates as a cost centre within the Board and through its detailed budgeting and monitoring system it endeavours to create a commercial environment within which its managers are required to operate. An illustration of this is where services are provided by one department to another. The fact that the cost of such services has to be accepted by another cost centre does not absolve the manager of the department providing the service from having to justify the gross costs of the operation under his control; he has to justify the need to retain resources, part of which are being used by his department and part charged out to other users.

SOUTH EASTERN REGION

3.35. We also examined the budgeting procedures operating in the South Eastern Region (SER) and ascertained that there were no differences in principle in the operation of the system. There were minor variations in the application and monitoring that stemmed from the delegation of authority that devolves upon each region. Of necessity the plans, budgets and measurement of outturn against budget are recorded and submitted on standard forms. We gained the impression that the present differences in the recording of supporting financial information could be significantly reduced within the next three years, since a computerised system is being developed by the Board in the North Eastern Region for eventual use by all regions.

MIDLANDS AND SOUTH EASTERN REGION

3.36. A summary of outturn against budget for Midlands Region and South Eastern Region, for the five years ended 31 March 1980, is at Appendix 5. Despite some wider variances relating to individual categories of costs, variances in respect of overall net expenditure have been contained within the range of ± 2 per cent of budget, with outturn exceeding budget for South Eastern Region in 1975–76 (1·9 per cent), 1978–79 (1·7 per cent) and 1979–80 (insignificant). Variances for Midlands Region range from $-1{\cdot}7$ per cent (1975–76) to $-0{\cdot}3$ per cent (1978–79). It will be noted that, in recent years, both fuel and other costs (OMGS) in the MR exceeded those of SER. This is because Midlands Region has the majority of the Board's modern 500 MW coal-fired units and has in the last two years generated some 30 per cent of the Board's total output. It might be considered that the pattern would be repeated with regard to salaries, but, in the event, the amount expended in the SER has been greater than in the MR. We have ascertained that the three main reasons for this are:

(i) the preponderance of older, labour intensive stations in the SER;

(ii) the large and important engineering department needed to support the older stations and the three new major stations, Dungeness, Grain and Littlebrook, which are being commissioned in the SER; and

(iii) the impact of London Weighting on salary costs.

STATION COST CONTROL

3.37. Set out at Appendix 6 is the organisation chart of the MR power station at Ratcliffe-on-Soar and, at Appendix 7, a Statement of Resource Management (SRM 1) upon which details of station performance against budget are reported each month. This statement is accompanied by the form used to record commitment to spend, which, as discussed in paragraph 3.27, is also monitored against budget.

3.38. From SRM 1 it will be seen that lines 1–8 give certain technical details, lines 9–10 show fuel costs, lines 11–14 give salary costs and lines 15–23 provide further information on employment. At lines 24–30 details of other costs are given, which, together with fuel and salary costs, produce the total station cost at line 31. Lines 32–43 provide an analysis of total expenditure in a different format as an additional means of station control.

Divisions and headquarters departments—general

3.39. The budgetary procedures referred to above also apply to the services, divisions and headquarters departments, but whereas in the stations/regions the greater emphasis is inevitably on control of fuel costs, in the divisions and headquarters departments the most crucial control is of salaries and related costs.

DIVISIONS

3.40. The Generation Development and Construction Division (GDCD) which is based at Barnwood, near Gloucester, is responsible for the layout of new power stations and the oversight of their construction. At Appendix

8 a summary is given of outturn against budget over the last four years. It will be seen that costs have been contained within the budget during this period, but an attempt to reduce expenditure in 1979–80 by £1·2 million, as a contribution towards public spending cuts, achieved a saving of only £100,000. Of the total amount expended over the last four years, 65 per cent of costs have been capitalised and the balance has been included under revenue expenditure. The criterion for capitalisation of these costs is that they have been incurred in the creation of an asset.

HEADQUARTERS DEPARTMENTS

3.41. The headquarters departments provide central administration and a wide range of services to the Board as a whole. At Appendix 9 a summary is given of outturn against budget for the four years to 31 March 1980. In addition to the regular control by way of resource costs there is also the control by way of department, and Appendix 10 shows how the respective departments performed against budget in 1979–80. Some of these departments have been amalgamated, eg computer centre and computer planning and development, so that as previously stated there are now seven headquarters departments. The largest underspend (£2 million) was in the planning department, as a result of delay in connection with uranium ventures. The Board has told us that there is particular difficulty of prediction in relation to these activities. In terms of performance against budget the departments as a whole have done well. In each of the four years, expenditure has been contained within the set target.

The Board as a whole

3.42. In order to appraise the Board's total performance against budget, we obtained details of outturn, together with the budget estimates for the five years to 31 March 1980. This information is displayed at Appendix 11, broken down over the various major cost categories, from which is deducted miscellaneous income to give total net expenditure. In each of the five years, total net budgeted expenditure has been contained within the budget, with variances ranging between −0·1 per cent (1975–76) and −1·1 per cent (1976–77). Certain expenses, included in the Board's Revenue Account, are considered not to be within the control of operational management and these are, therefore, excluded from revenue expenditure budgets. We have examined the reconciliations between outturn figures, prepared on the same bases as those used to establish the budgets, and those published in the Board's Annual Report and Accounts.

Other cost control matters

PLANT MAINTENANCE—MAJOR UNFORESEEN BREAKDOWNS

3.43. In addition to the normal preventive maintenance programme and the minor repairs that have to be carried out at all stations there is also the likelihood that a number of major unforeseen breakdowns will occur. In earlier years each region has carried a contingency fund to meet such expenditure, but because there has tended to be an overestimate of the total amount required the procedure in the latest two years has been for the contingency fund to be held centrally at headquarters. In the year to 31 March 1980 an amount of £11·25 million had been earmarked as the central contingency fund but in the event total expenditure amounted to some £13 million. As a cost cutting exercise in the current year no contingency fund has been set aside and the regions are endeavouring to achieve savings against the normal maintenance budgets to match the cost of breakdowns wherever they occur. This will probably entail one region 'using' part of another region's budget because it may not be possible to achieve the required level of savings in the region where these breakdowns occur. The Board contends that the effect of this policy is to introduce a fairly severe degree of stringency into regional operating budgets.

GOOD HOUSEKEEPING

3.44. In the course of our review of the Board's internal cost control, we took note of such aspects of 'good housekeeping' as:

(i) internal audit;

(ii) cash management;

(iii) property management; and

(iv) disposal of by-products and surplus assets other than land and buildings.

In the following paragraphs, we deal in turn with each of these matters.

Internal audit

3.45. The Board's internal audit organisation is responsible to the Director of Finance but also has an independent functional link direct to the Executive. The Board has established a Review Committee to act in an audit capacity, constituted of the part-time members of the Board and chaired by the Deputy Chairman. Its terms of reference include a periodic review of the internal audit function. As defined by the Board, the broad objective of internal audit is to examine the use of financial and physical resources to ascertain how effectively the Board's policies are being executed and how efficiently they are operating. Its role fully encompasses the audit of accounting and financial control systems and the verification of expenditure on approved goods and services in accordance with the various regulations currently in force. It is also actively concerned with 'value for money' in the economy and efficiency of the Board's operations.

3.46. Managed as a centralised function from Board HQ, the internal audit staff, numbering 66 at March 1980, is divided into units located in each of the five regions, at Barnwood and at Board HQ. About half of the internal auditors hold a professional qualification. New entrants to internal audit are required to hold such a qualification or to have made significant progress towards qualification. The function is seen as an ideal training medium for other financial duties within the Board and the rate of staff rotation in recent years has consequently been high.

3.47. On average, some 300 audit reports are produced each year and discussed, prior to issue, with the line managers concerned. Minor matters are cleared with functional officers. Copies of the reports are widely circulated to senior management, including the Head of Internal Audit and the external auditors (Peat, Marwick, Mitchell and Co). Summarised audit reports are submitted every four months by local internal audit managers to their regional/divisional management for discussion at Director General/Director level. Copies sent to the Head of Internal Audit form the basis for his corresponding four-monthly report to the Executive. Continuing and reciprocal contact is maintained between internal audit and the external auditors.

3.48. In the course of our review, we obtained a selection of internal audit reports in respect of regions and power station construction sites together with the resultant correspondence. A study of these documents showed that management response in respect of 'custodial audit' and routine procedural investigations is prompt and satisfactory. There are proper procedures clearly laid down and the management response is straightforward in that it involves the enforcement of established rules.

3.49. The control of stores, stocks, and cost reimbursement and extra-contractual work seem to provide continuing problems for management, as evidenced by the recurrence of such items in the internal audit reports. In particular 'significant weaknesses in control of time and material contracts' in four regions during 1979 were considered important enough to be brought to the attention of the Executive in a four-monthly report issued by the Head of Internal Audit. Although the individual sums of money involved are small in the context of the Board's total expenditure, the stance taken by the internal audit staff, and the response of all levels of management to these findings gives an indication of the Board's commitment to keep such costs under control through the operation of the established procedures.

Cash management

3.50 Cash management within the Board is primarily concerned with the efficient control of authorisation and effecting of payments. In the financial year 1979–80 these payments amounted to some £600 million on capital schemes and some £4,000 million on revenue items. Of these at least some £2,800 million (70 per cent) was accounted for by purchases of fuel and electricity, some £500 million (12 per cent) by salaries and wages payments and the balance in respect of other materials, goods and services (OMGS).

3.51. Capital and fuel payments involve a few major suppliers where the terms of trade and payment are governed by pre-determined arrangements. Such arrangements enable the Board to control the amount and the timing (to a specified day in some cases) of payments in respect of some 70 per cent of the Board's total outgoings.

3.52. The Board makes extensive use of the Bankers Automated Clearing Services (BACS) system for the payment of all salaries, some wages and as many OMGS payments as possible where suppliers are prepared to accept payment by Traders Credit. Such a procedure reinforces the Board's control over the value and timing of these types of payments, because the charge to the Board's bank account can be pre-determined to a specific date.

3.53. The Board has not been completely successful in persuading suppliers to accept payments by Traders Credit, but there is a continuing effort to effect such a change. A similar situation exists in the payment of wages. Some wages still have to be paid in cash (ie notes and coin), with the attendant problems and cost of security and the continuing risk of robbery and injury to staff involved.

3.54. We were told by the Midlands Region finance staff that in conjunction with a special internal audit exercise on the operation of the BACS system, consideration is being given to the establishment of an on-line computing facility with BACS. This would very considerably speed up the transfer of payment information to BACS and avoid much paperwork and the cost of its transport. This indicates the involvement of the Board's staff in the improvement of the efficiency of the payments procedures.

3.55. Receipts by the Board from non-Area Board sources are some 2 per cent of the Board's income, and encompass sales of electricity to railway undertakings and other direct customers, sales of steam, ash and sundry other items. Although small in percentage terms such direct income amounted to some £110 million in 1979–80. Care is therefore exercised in the control of the amount and timing of such receipts. The balance of the Board's income in 1979–80 is accounted for by sales of electricity to the Area Boards under the terms of the Bulk Supply Tariff (BST).

3.56. The need for payments and receipts through the banking system between the Area Boards and the Board in respect of electricity supplied under the BST has been obviated by the operation of a 'Clearing House' by the Electricity Council on behalf of the Electricity Supply Industry (ESI) as a whole. The Board is credited with its share of proceeds of sale of electricity by means of a book transfer between the Board and the appropriate Area Board. Such receipts are offset against the funds provided through the Electricity Council, which provides a corporate treasury function for its own activities and those of the CEGB and the Area Boards.

3.57. The corporate treasury function exercised by the Electricity Council on behalf of the ESI includes an agreement with the clearing banks to transer daily all Board bank balances (both in credit and in overdraft) to the Electricity Council's bank account. This long-standing arrangement in the ESI prevents cash balances standing idle, and, of particular importance to the Board, minimises overdraft interest and bank transaction charges.

3.58. The Board operates a system of long and short-term cash forecasting. Seven year estimates are compiled from the latest September Outline Plan (SOP) to assist the Electricity Council in their management of the ESI's cash flows. These estimates are considered by the Department of Energy, when they set the external financing limits for the industry as a whole. Short-term cash forecasting, both within the Board's regions and divisions, and nationally, is used to give the Board day-to-day control of cash disbursements and early warning of any action that may be necessary to stay within the Board's share of the ESI's current external financing limit.

Property management

3.59. We enquired as to the Board's policy in respect of the management of its stock of land and other property. The Board currently owns some 48,000 acres, of which approximately 7,000 acres of mainly agricultural land are held for future operational use, with another 2,500 acres of mixed urban and rural land having been identified as available for disposal immediately or within the next three years. The balance of about 39,000 acres is occupied by 132 operating power stations, 202 grid sub-stations and a variety of office buildings, research laboratories, workshops, stores, sports grounds, training centres and houses. The Board told us that its policy is to own sufficient land to carry out its business efficiently having regard to the protection of its installations and to minimising effects upon the environment. A continuing review is carried out of land and property held for future development. In the light of diminishing demand projections and changes in technical requirements the list of retentions has already been much reduced. The Board's Surveyor manages HQ and divisional property and provides professional advice to regions on matters of estate management generally. Gross proceeds of sale from land and buildings have amounted to £10·15 million over the five years to 31 March 1980. In addition, in 1979–80, further property was disposed of by way of lease or letting, to produce an annual income of approximately £562,000.

Disposal of by-products and surplus assets

3.60. We also considered the Board's procedures in relation to the disposal of by-products and surplus assets, other than land and buildings. We found these to be well organised and subject to appropriate levels of delegated authority and accountability.

Financial aspects of project control and control of expenditure against annual capital budgets

3.61. The bulk of the Board's capital expenditure relates to power station construction. For this reason, we concentrated our review on the Generation Development and Construction Division (GDCD). The division is referred to generally, throughout the industry, as Barnwood.

3.62. The matters covered in paragraphs 3.63 to 3.86 are as follows:

(i) procedures for approval of spending;

(ii) monitoring of costs against scheme sanction and contract authorisation;

(iii) a summary of the estimated costs to completion of power stations currently under construction;

(iv) comparison of actual/outturn expenditure with approved divisional capital budgets:

(a) monthly reports; and

(b) review of divisional outturn results against approved supplemented capital budgets, 1976–77 to 1979–80.

PROCEDURES FOR APPROVAL OF SPENDING

3.63. The procedures for approval of spending followed at Barnwood accord with the Schedules of Delegation of Authority set out in the Board's Directive on Organisation and Management and the Board's Directive on Financial Control. Within the broad guidance provided by these two Board directives, there are detailed Divisional procedures in connection with delegations of authority and procedures for monitoring costs against scheme sanction and contract authorisation.

3.64. In the case of a proposed new power station, the first stage of approval of spending is the specific inclusion of the scheme in the Board's investment proposals submitted to the Secretary of State for Energy for his approval. In addition, separate sanction for the project itself must be obtained from the Secretary of State. The project will be included in the Division's capital budget, in advance of Government approval, if such approval would give rise to expenditure during the budget year. It is a normal condition for financial sanction of a project that it shall have been provided for in the annual capital budget. The scheme (including preliminary works) cannot proceed to sanction until the Director of Planning has issued the relevant Letter of Authority and Station Development Particulars. Subsequent to the issue of the authority to proceed, it would be normal for a paper outlining the strategy for constructing the station to be presented to the Executive, followed in due course by application for financial sanction for preliminary works, including design. At this stage, in those cases where special justification is provided, materials which require early ordering and some initial contracts may also be authorised by the Executive.

3.65. In due course, a paper is presented to the Executive, inviting them to sanction the estimated total capital cost of the station in a stated sum including an identified amount for risk margin (see paragraph 3.75(i)) and to release the project for construction. At the same time, the Executive is invited to cancel any existing preliminary scheme sanction in connection with the project and to authorise any necessary adjustment to the current annual capital budget, which may arise from the more accurate estimate of costs to be incurred within the current budget year.

3.66. In addition to the exclusive power to sanction all projects of more than £4 million, the Executive have reserved to themselves the authorisation of all contracts in respect of boilers, turbo-generators and nuclear reactors. It is usual, therefore, for application to be made to the Executive for authorisation of such contracts either concurrent with the application for sanction of the estimated total capital cost of the new power station, or shortly thereafter.

3.67. Matters relating to the proposed construction of a new power station are subject to continual discussion between the Division, the Executive and HQ officers. The various sanctions and authorisations represent the formalisation of decisions taken as a result of consultation and debate over a considerable period.

3.68. Scheme sanctions and contract authorisaitons are granted at stated base date price levels. Estimates of both price escalation and interest during construction are included in the applications for sanction, but the Executive recognise the inevitability of these items and the uncertainty of their prediction. For these reasons, coupled with the requirement to monitor performance in real terms, the basic monitoring of costs against scheme sanction and contract authorisation is conducted initially by reference to the base date price levels, with the estimated cost to completion (ECTC) and balance of current sanction expressed in those terms. Price escalation from scheme base date to the reporting date is then added to produce the ECTC as at the reporting date. Whilst records are kept of interest during construction (IDC) and figures are published by the Board, this item does not feature in the costs which are monitored, on a monthly basis, against scheme sanction. We have been told that the Board concentrates its monitoring on those things within CEGB control. Construction costs and time are the two factors within the Board's control which determine IDC and it is to these factors that the Board gives its attention. Nevertheless, the Board has now set a requirement for the annual presentation to the Executive of the originally estimated and currently predicted IDC for each station under construction.

3.69. Below the overall scheme sanctions, and contract authorisations granted by the Executive, the Director General has considerable power to commit the Board and to authorise expenditure. These powers and those which the Director General has delegated to divisional directors and other officers are clearly set out in detail in the divisional procedures, referred to in paragraph 3.63.

3.70. Thus the day-to-day business of managing power station construction and the approval of spending is conducted by the Director General and his officers within their delegated powers, subject to the overriding restraint of the sanctions and authorisations granted by the Executive.

3.71. It is a fundamental rule within the division that at no time should the ECTC be allowed to exceed the existing scheme sanction, including Risk Margin. This possibility should be highlighted by the monitoring process revealing that 60 per cent of the scheme risk margin has been committed/reserved. At this stage, a review of the ECTC must be made to see whether the project can be completed within the existing sanction. If it cannot, application must be made to the Executive for sanction of a partial or full scheme revision, according to circumstances.

3.72. Our discussions with officials at Barnwood, at Director General, director and middle management level, together with sight of examples of various returns to local directors and to the Executive, indicate that all laid down procedures for approval of spending, including commitment to spend, which is regarded as crucial, are followed to the letter.

3.73. A financial review of capital schemes, presented to the divisional directors' meeting on 13 August 1980, indicated that in the case of two stations the ECTC exceeded the current sanction. These were Dinorwic (excess £4·4 million) and Dungeness 'B' (excess £36·6 million). In the case of Dinorwic, a revised scheme paper was currently being redrafted following discussion with the Director of Finance. In the case of Dungeness 'B', it was stated that APC Ltd (see Chapter 12) had not yet completed the revised station estimate, but that a revised scheme would be submitted to the Executive as soon as this estimate was received by the division.

3.74. Whilst the above paragraph would appear to contradict the assertion at the end of paragraph 3.72, the current divisional rules were not promulgated until December 1979 and the problems in regard to these two stations had been in existence at that time. Both cases were being handled in accordance with the Board's Directive on Financial Control, which requires that a scheme revision should be initiated 'immediately it becomes apparent from the ECTC that a scheme is likely to exceed the sanctioned sum'. In these circumstances, the Directive places an embargo upon entry into additional commitments until a revised scheme has been sanctioned. In the case of Dinorwic, revised estimates have since shown that the station can be completed within the sanctioned sum. As stated in paragraph 3.73 the Executive are to be presented with a partial scheme revision for Dungeness 'B' in the near future. In the mean time, the Executive, being the party which granted the original sanction, have been kept fully informed of the situation.

MONITORING OF COSTS AGAINST SCHEME SANCTION AND CONTRACT AUTHORISATION

3.75. The divisional procedures for monitoring costs against scheme sanction and contract authorisation are very detailed and somewhat complex. This is inevitable in view of the need to ensure proper control over risk margins, whilst at the same time using the proportion of risk margin committed/reserved to act as an early warning to review estimated costs to completion against scheme sanction or contract authorisation. We quote below some of the basic principles underlying these procedures:

(i) costs are monitored and controlled against a predetermined estimate which is arrived at by aggregating the basic costs (including disclosed provisional and prime cost sums) and then adding an amount, known as the risk margin, to reflect the division's assessment of the financial uncertainty attached to that estimate. The aim is to provide an estimate which reflects a realistic outturn (in base year prices) at the time sanction is given;

(ii) costs should not automatically be allowed to rise to the predicted level and control of expenditure should always be exercised so as to hold total costs to the minimum necessary to achieve programme and approved standards;

(iii) specific reference is made to the methods to be used in controlling the appropriate scheme and contract risk margins as it is fundamental to the control arrangement that the scheme and all contracts included therein remain within the authorised limits, not only in terms of the current commitment but also in terms of their predicted outturn;

(iv) proper control over scheme costs is achieved by the continuous monitoring of individual contract costs from the commencement to the end of the project. These costs are monitored at base date prices, whilst a thorough check is made of claims for escalation to ensure that these claims comply with contract provisions and that the appropriate indices have been used in their calculation;

(v) to ensure strict scheme control, no commitment is entered into unless there are sufficient funds available, either in basic costs or out of the risk margin. In the case of contract expenditure, a further control is that where the contract sum is likely to be exceeded, commitment will only be entered into if additional contract authorisation is obtained. At that time it will be necessary to know from where the work is being funded, within the overall scheme sanction. in cases of emergency, directors may take appropriate action in advance of sanction but steps must be taken to obtain approval without delay; and

(vi) to facilitate the monitoring of costs, the financial records analyse basic costs and scheme risk margin by main sections, such as Land, Civil Works, Boilers, Electrical Plant and so on; and, where appropriate, by individual contracts. The records will also show for risk margin the movement of cost from one of the following categories to another, until expenditure takes place.

(*a*) Unallocated – scheme risk margin not yet allocated to a specific contract or area of cost.

(*b*) Allocated – scheme risk margin allocated to a particular contract (or area of cost)—specific work not yet identified.

(*c*) Reserved – risk margin specifically reserved for known work—formal commitment not yet entered into.

(*d*) Committed – cost committed contractually.

(*e*) Expended – amount certified for payment.

3.76. Introduction of the concept of risk margin gives more flexibility to the division's financial control system. This concession was granted only on the understanding that the reporting system would be sufficiently concise and frequent to enable the Executive and divisional management to be kept up-to-date on the financial progress of schemes and, where appropriate, individual contracts. Although individuals will continue to have the right to call for financial information on an *ad hoc* basis, the following standard periodic returns are produced.

Monthly reports

(*a*) Report for project managers. This statement shows the latest ECTC for the station, analysed over main sections, compared with sanctioned sum, both at scheme base date prices, together with a detailed analysis of how scheme costs are being met from the risk margin. Price escalation to date and ECTC at current date are likewise recorded. Key details of major (Executive and Director General approved) contracts are provided as an attachment to the report. Particular attention is given to the percentage of the scheme risk margin (and main sections thereof) committed and reserved at the time of each report;

(*b*) Report to directors. This report includes a statement in similar format to that provided for project managers, but, with the exception of the reports for Directors of Projects, normally shows only the total for each scheme. In the commentary, changes from previous months will be referred to, together with any other significant matters for the attention of directors; and

(*c*) Report to Executive. The Director General reports interim information between quarterly reports.

Quarterly reports

(*a*) Report to Executive. This report comprises a commentary on all stations under construction and includes statements in similar format to those referred to above, but containing some additional information. This additional information includes:

(i) comparison of current estimated commissioning dates with the original predictions;

(ii) costs of delay shown by way of memorandum;

(iii) percentage of scheme risk margin committed.

(*b*) Report to directors. This report will be in the same format as that referred to above, with the addition of a statement showing the financial position on major contracts. Other contracts may be included at the discretion of the appropriate Director of Projects.

Other reports

The procedures provide for annual reports to be issued, showing the cost of interest during construction and highlighting how increased costs, inflation and delay in commissioning affect this item of the Board's finances. Other reports on specific matters called for by managers, directors or members of the Executive are prepared as required.

3.77. We have received examples of the monthly and quarterly reports referred to above, and have discussed them with directors and finance officers at Barnwood. Our study of these reports, and our discussion of them, indicate that they have been prepared in accordance with the laid down procedures.

3.78. In addition to reviewing standard reports prepared in accordance with divisional procedures, we have also observed the continuous monitoring of costs against contracts and negotiations with suppliers. In the course of discussions, formal and informal, with middle management officers in the commercial (finance and contracts) department at Barnwood, we had the opportunity to inspect working books and documents. These included:

(i) Report of the Cost Assessment Panel on the NEI/CC tender for boilers for Heysham II and Torness. This report, dated 28 November 1979, recommends very considerable reductions to the tender price under most sections, but, for reasons of commercial confidence, the actual tender figures are not quoted in the report;

(ii) Various reports supported in some cases by copy correspondence, detailing negotiations with suppliers for compensation for delay, faults in equipment and similar claims; and

(iii) A paper, detailing the Board's past and present practice in relation to contract price adjustment for price escalation.

From this part of our review, we formed the positive impression that Barnwood's commercial department warrants its title and pursues its day-to-day function in a thoroughly commercial and effective manner.

ESTIMATED COSTS TO COMPLETION OF POWER STATIONS CURRENTLY UNDER CONSTRUCTION

3.79. The estimated costs to completion of these stations, seen as at 31 March 1980, are set out in Table 3.2. This table records the reasons for change in ECTC from the amount of the original sanction to that envisaged at 31 March 1980, all expressed at scheme base date prices. Provision for price escalation at 31 March 1980 is then added to produce the ECTC as seen at March 1980. The figures are supported by details of the type of station, the number of units and design net capability, the planned year of commission and the period from start on site to probable year of commissioning of the last unit.

3.80. Some idea of the increases in construction costs arising from delay can be obtained from Table 3.3. This table picks up in column (3) the costs of delay at scheme base date prices, as recorded in column (5) of Table 3.2, and compares them with the costs of delay including escalation to 30 June 1980 (column (4)). The figures quoted in Tables 3.2 and 3.3 are derived from financial reports prepared on a regular basis at Barnwood, in accordance with divisional procedures.

3.81. The Board has told us that the calculation of estimates of the cost of delay is somewhat arbitrary at times, in that it is difficult, for example, to distinguish between under-estimating and time overruns. For this reason, the sums recorded as cost of delay in Tables 3.2 and 3.3 must be regarded as best estimates rather than as precisely calculated figures.

COMPARISON OF ACTUAL/OUTTURN EXPENDITURE WITH APPROVED DIVISIONAL CAPITAL BUDGET

3.82. The preparation of budgets for capital expenditure involving high technology, large scale factory production and long-term site erection, is extremely complex. The difficulties of forecasting are compounded by problems related to design and other technical matters causing delay and aggravated by uncertain levels of productivity, strikes on sites and other industrial relations matters.

3.83. Each month statements are prepared, comparing actual expenditure to date and predicted outturn figures for the year against both the approved budget and the approved supplemented budget for the comparable periods. Project managers receive a statement in respect of their particular project, directors receive a statement analysed over all projects, whilst the statement for the Executive sets out year to date information for the division as a whole and predicted outturn figures for individual projects and the division as a whole. These statements are accompanied by detailed commentaries highlighting and providing explanations for variances from budgeted figures.

TABLE 3.2 **Generation Development and Construction Division**
Estimated costs to completion (ECTC) of power stations currently under construction (* excluding Heysham II)

		SCHEME BASE DATE PRICES							
£m	*Scheme Base Dates* (1)	*Original Sanction Excl Tolerance/ Risk Margin* (2)	*Changes in Design or Policy* (3)	*Net Under/(Over) Estimations* (4)	*Estimated Costs of Delays*† (5)	*Unallocated Scheme Tolerance/ Risk Margin* (6)	*ECTC at Scheme Base Date Prices* (7)	*Price Escalation to 31 Mar 80* (8)	*ECTC including price escalation to 31 Mar 80* (9)
Conventional Stations									
Dinorwic	Dec 1973	116·0	21·8 §(changes in accounting practices)	14·6	25·4	5·1	182·9	219·1	402·0
Drax Completion	Mar 1978	606·3	3·7	—	—	78·8	688·8	201·8	890·6
Grain	Dec 1970	209·9	8·7	14·2	41·4	4·5	278·7	295·2	573·9
Ince 'B'	Jan 1972	109·5	1·4	1·6	33·0	0·9	146·4	125·6	272·0
Littlebrook 'D'	Jun 1973	183·2	22·4	5·7	29·3	2·4	243·0	252·2	495·2
Nuclear Stations (excluding Nuclear Fuel)									
Dungeness 'B'	Mar 1965	88·5	24·8	‡63·0	40·2	—	216·5	243·5	460·0
Hartlepool	May 1967	91·8	52·1	9·9	59·2	6·5	219·5	235·6	*455·1
Heysham I	Dec 1969	142·3	33·9	10·1	35·5	8·0	229·8	221·0	*450·8

* Not yet under construction.

† Includes settled claims at prices ruling at date of settlement and outstanding claims at March 1980 prices.

‡ Comprises changes due to under-estimation of original design, fundamental data during construction and new commercial arrangements following collapse of original consortium.

§ Excluding possible provision for buffer fuel storage, estimated at £12·5m per station.

TABLE 3.2—*continued*

	Scheme Base dates	Type	No of units and design net capability MWso	Planned year of commission	Year of start on site to probable year of commissioning of last unit
Dinorwic	Dec 1973	Hydro (pumped storage)	6×250	1979–81	1974–83
Drax completion	Mar 1978	Coal	3×660	1984–86	1978–86
Grain	Dec 1970	Oil	*5×660	1976–79	1971–83
Ince 'B'	Jan 1972	Oil	2×500	1977	1972–82
Littlebrook 'D'	Jun 1973	Oil	3×660	1979–81	1974–83
Dungeness 'B'	Mar 1965	AGR	2×600	1970–71	1966–81
Hartlepool	May 1967	AGR	2×660	1974	1968–82
Heysham I	Dec 1969	AGR	2×660	1976	1970–82

Sources: Financial items and scheme base dates—GDCD Barnwood.
Other information—*CEGB Statistical Yearbook* 1979–80, page 14.

* Three units only currently programmed for completion. No decision has been taken by the Board to complete units 4 and 5.

TABLE 3.3 **Generation Development and Construction Division**
Power stations under construction—estimated cost of delay

	(1) Scheme base date	(2) Original sanction excluding tolerance/risk margin	(3) Cost of delay as at 31.3.80 expressed at scheme base date prices £m	(4) Cost of delay including price escalation to 30.6.80 £m
Conventional stations				
Dinorwic	Dec 1973	116·0	25·4	84·0
Drax completion	Mar 1978	606·3	—	—
Grain	Dec 1970	209·9	41·4	153·1
Ince 'B'	Jan 1972	109·5	33·0	74·2
Littlebrook 'D'	Jun 1973	183·2	29·3	61·7
Nuclear stations				
Dungeness 'B'	Mar 1965	88·5	40·2	101·1
Hartlepool	May 1967	91·8	59·2	130·4
Heysham I	Dec 1969	142·3	35·5	107·7

Source: Barnwood.

3.84. The essence of the Barnwood operation in the field of financial control is contract negotiation and letting, followed by control of costs against contracts and the monitoring of overall scheme cost against scheme sanction. Monitoring of expenditure against the annual capital budget is regarded as important, but secondary to the control of costs against contracts. In respect of the 1980–81 capital budget, the Executive has expressed the view that it was not its intention that the commissioning dates of power stations should be prejudiced in order to meet the net budget. The Executive went on to say that if, at any stage, the outturn forecast were to exceed the budget, after allowance for slippage, then it would have to advise 'an appropriate action in the light of the overall position'. That overall position would take account, we were told, of the Board's aggregate capital position against budget, its expected outturn for the year against the EFL, and the economics of the individual power station case. The judgment made would take account of the additional cost that would arise for the Board, resulting from a forced loss of momentum on site.

REVIEW OF DIVISIONAL OUTTURN RESULTS AGAINST APPROVED SUPPLEMENTED CAPITAL BUDGETS, 1976–77 TO 1979–80.

3.85. The following table (Table 3.4) compares outturn results against capital budgets for the four years 1976–77 to 1979–80.

TABLE 3.4 **GDCD—capital budgets, 1976–77 to 1979–80**

Comparison of outturn with approved divisional supplemented budgets 1976–77 to 1978–79 and divisional expenditure limit 1979–80

	1976–77 £m	*1977–78* £m	*1978–79* £m	*1979–80* £m
Approved divisional budget*	351·2	293·5	336·8	465·0
Supplements:				
Inflation	26·7	18·1	17·8	31·3
Approved budget variations	—	—	29·6	1·4
Approved supplemented budget	377·9	311·6	384·2	497·7
Reduction re public spending cut†	—	—	—	(53·0)
Divisional expenditure limit	377·9	311·6	384·2	444·7
Outturn	336·7	330·9	354·2	438·9
Excess/(shortfall)	(41·2)	19·3	(30·0)	(5·8)

Source: The CEGB.

* Budget set at prices ruling in March preceding budget year.
† This was the major divisional contribution towards meeting CEGB's share of the reduction effected in the EFL for the ESI as a whole.

3.86. We have studied the commentaries submitted by Barnwood to the Executive in connection with the outturn reports summarised in Table 3.4. Whilst each outturn comprises a mixture of over- and under-spending on different projects, it is under-spending, due to delays arising from unforeseen technological problems and poor productivity, both in factories and on sites, that has predominated over the period.

Conclusions

The current financial target

3.87. We believe that the Board's cost minimisation programme will help to limit increases in costs. The Board can obtain only limited advantage, towards the achievement of the financial target, from an accelerated programme of disposal of surplus assets and possible reductions in the levels of fuel stocks and stores holdings. It is unlikely that the Board could, by reducing or making other adjustments to the BST, so stimulate demand as to reduce the adverse margin between unit costs and the average charge for electricity to any significant extent. This is especially true in the short-term. For these reasons, we believe that an inevitable consequence of the present financial target, if it is to be achieved in present circumstances, will in itself be a considerable increase in the price of electricity, staged over the next two years, to levels somewhat higher than those contemplated in the present plans of the industry.

The effect of the EFL

3.88. In paragraph 3.12 we referred to pressure from the EFL, in conjunction with a falling expectation of demand, causing the Board to make a substantial reduction in its investment programme for 1980–81. In present circumstances, with a continued drop in the expectation of demand, it is not possible for us to assess the severity of the constraint to be imposed by the EFL in 1981–82.

Internal cost control

3.89. The Board has a sophisticated and well documented system of revenue cost control, which the responsible officers operate in an efficient manner.

3.90. Since the demand for electricity is bound to vary from forecast, and because the costs of fuel and salaries have regularly increased from the budget price datum, the Board's budgets are flexed (paragraph 3.23) and supplemented (paragraph 3.22) to reflect such changes. In our view both flexing and supplementing, as practised by the Board, are necessary in order to establish realistic budgets and do not, of themselves, make the budgets easier to attain. These procedures need to be followed, in order to identify the true variance from the performance envisaged at the time the budget was set.

3.91. Whilst the revenue cost control system is effective for the control of costs against budgets, we cannot state whether the budgets themselves are as tightly drawn as is consistent with the planned level of generation. The fact, stated in paragraph 3.26, that regions have made substantial reductions in their OMGS expenditure budgets for 1980–81 and 1981–82 may suggest that these budgets were fairly easy to achieve in the past. It remains to be seen whether the desired savings in respect of plant maintenance, referred to in paragraph 3.43, can be achieved without adverse consequences, either elsewhere in generation costs or in later years. Nevertheless, in all our discussions about revenue cost control, at headquarters, in the regions and at power stations, we have been impressed by the concentration of attention on minimising operating costs, whilst still observing proper standards of safety and security of supply.

Internal audit

3.92. In our view the function of internal audit is pursued effectively. While the independence of the internal audit function does not flow naturally from the organisational structure, the operational relationship between internal audit and finance and the functions of the Review Committee ensure that *de facto* independence exists. We are of the opinion that the internal audit staff discharge their role within the Board competently and responsibly, and their relationship with the external auditors reinforces and supports the external auditors in their statutory role. Our review has shown that there have been minor instances where the Board's laid-down operating procedures have not been adhered to as closely as they should have been. Nevertheless, management response to audit findings is satisfactory. The role of internal audit within the CEGB is understood and accepted by management generally.

Cash management

3.93. The management of cash by the Board is carried out competently and has regard to the objective of keeping funds within the current financing limits whilst minimising the cost to the Board of such funds.

Property management and disposal of by-products and surplus assets

3.94. We are satisfied that the Board conducts its property management in accordance with the perceived needs of its business and with due regard to economy. Proper commercial arrangements are made for disposal of by-products and surplus assets, including land and other property assets.

Approval of capital spending

3.95. Our review has established that there is a lengthy, but well defined, series of procedures for approval of capital spending, commencing with submission to the Secretary of State for Energy and passing down through the Board, the Executive (advised by the Director of Finance and other Chief Officers), the Director General of GDCD and his properly delegated officers. We are satisfied that these procedures ensure that expenditure is sanctioned at appropriate levels of authority and that the specific requirement to keep the party, which granted financial sanction for a project, fully advised of the progress of spending (including commitment to spend) is observed at all times.

Monitoring of costs against scheme sanction and contract authorisation

3.96. Barnwood has detailed procedures laid down for recording and reporting costs as incurred against scheme sanction and contract authorisation, which supplement the Board's Directive on Financial Control. Whilst we consider that the terms of the Board's Directive provide a proper control over revenue and capital expenditure, we welcome the more stringent procedures laid down at Barnwood in respect of construction costs. These procedures require potential problems to be identified within the division at an earlier stage than called for by the Executive, thus giving more time for their solution by the division within the existing scheme sanction. If the problems cannot be resolved within the existing sanction, more time is given for the preparation of an appropriate scheme revision, as required by the Board's Directive. We are satisfied that Barnwood's procedures are fully adequate for their purposes and are implemented efficiently. The regular reporting system in operation ensures that all levels of management are kept informed of the financial position as it develops at each station under construction, in such detail as is appropriate to each particular management level.

3.97. We are also satisfied that the substantiation of charges rendered and claims made under contracts, including claims for contract price adjustment made under the price escalation clauses in appropriate contracts, are skilfully and thoroughly pursued by staff well qualified for these tasks.

Estimated costs to completion of power stations currently under construction

3.98. We are satisfied that the analyses provided in respect of the changes in ECTC between scheme base dates and reporting dates keep management aware of the financial consequences of changes in design or policy and the increases in construction costs arising from delay.

Comparison of actual/outturn expenditure with approved divisional capital budgets

3.99. Barnwood has a routine system for reporting actual/outturn expenditure against capital budgets, supported by detailed commentaries on variances. We are satisfied that these reports give adequate information to all levels of management. As a result of our review, we are of the opinion that the scale of variances from capital budgets, shown in Table 3.4, does not reflect incompetence on the part of Barnwood in setting budgets and controlling expenditure against them. Rather, it reflects the problems discussed in Chapter 12.

CHAPTER 4

Investment background

4.1. The CEGB's planned investment programme at March 1980 price levels is expected to double from about £600 million in 1979–80 to about £1,200 million in 1986–87. Over the period as a whole, generation projects account for about 80 per cent of the programme, with the remainder split approximately equally between transmission and miscellaneous items. To put these figures in perspective, £600 million was about 2 per cent of national gross domestic fixed capital formation other than for dwellings in 1979 and about 9 per cent of gross fixed manufacturing investment.

4.2. The Board's investment programme derives from the objective of the electricity supply industry. This is expressed in the 1979–80 Development Review as 'to maintain and develop supplies of electricity to meet the needs of customers in England and Wales on a continuous basis as cheaply as possible'. Planning and appraisal of new investment is undertaken within the context of a strategy for meeting this objective. The Review states:

> 'the basic elements of the Board's long-term development strategy for best meeting this objective are well defined and stable from year to year and consist of:
>
> (i) developing nuclear power;
>
> (ii) containing costs;
>
> (iii) diversifying fuel sources to avoid excessive dependence on one single source'.

Under section 8(4) of the Electricity Act 1957, the annual investment programme which contributes to meeting these objectives requires the approval of the Secretary of State for Energy, for whom the Board prepares an annual Capital Investment Memorandum.

4.3. Our discussion and assessment of the CEGB's investment planning and appraisal procedures is developed in the following way. In this chapter, we examine the procedures for deciding how much generation capacity is needed to satisfy the electricity supply industry's interpretation of its statutory responsibility to continue to give a supply sufficient to meet the demand of all consumers connected to the distribution network. This may require the ordering of new capacity, which is expected to begin being commissioned six years after the order is placed, giving a lead time for planning of seven years. The Board therefore makes estimates of the peak demand it must meet in the seventh and subsequent years ahead. We discuss demand forecasting in paragraphs 4.8–4.27. Because the level of peak demand is potentially sensitive to charges for electricity, we then examine in paragraphs 4.28–4.41 the structure of the bulk supply tariff used by the CEGB for sales to the Area Boards.

4.4. The total generating capacity required in the seventh and subsequent years ahead is related to the forecast peak demand via the planning margin. The size of the planning margin used by the CEGB is determined by the security of supply standard which defines the industry's aims for security of supply over the winter peak period, and by assumptions about plant availability, weather conditions and the level of demand. The determination of the security of supply standard and the planning margin, and the reliance on the planning margin in the CEGB's decision-making are discussed in paragraphs 4.42–4.63.

4.5. Investment planning and appraisal are one process. In Chapter 5 we examine the Board's appraisal of alternative options for meeting future requirements of generation capacity. The economic analysis of each is based on discounted costs, including the effect on the whole system of introducing new capacity. The basic framework for investment planning and decision-making is discussed in paragraphs 5.1–5.18.

4.6. The appraisal results are highly sensitive to assumptions about the future behaviour of:

(i) fuel prices;

(ii) plant construction costs and completion times; and

(iii) plant performance.

We examine the CEGB's record on, and current procedures for, forecasting these in paragraphs 5.19–5.91. Then, in paragraphs 5.92–5.111, we discuss the treatment of uncertainty in the CEGB's investment appraisals, and the presentation of appraisal results both internally and externally.

4.7. The CEGB has told us that the 'planning background' against which it evaluates alternative investments assumes plant refurbishment on a significant scale. We discuss the CEGB's analysis of plant refurbishment and conversion in paragraphs 5.112–5.120. Finally, in view of its importance in future investment we examine the CEGB's development of the case for nuclear generation in paragraphs 5.121–5.134. This covers the longer-term programme identified in the Medium Term Plan for the electricity supply industry, to which the Board is not firmly committed, and the appraisal of Heysham II, which the CEGB has now ordered.

Demand forecasting

Procedures

4.8. The demand forecasts used by the CEGB in its investment planning are made on behalf of the electricity supply industry by the Electricity Council, which amalgamates the forecasts of the Generating and Area Boards with its own forecast of annual and peak demand for seven years ahead. When agreed by the Council this becomes the 'adopted' forecast and is used for medium-term planning. A Load Forecasting Group assists the Council; this is composed of one member each from the CEGB, and the Electricity Council, and three Area Board Chairmen. In May or June the Group settles the assumptions needed for forecasts, and in September the actual forecasts are agreed. To help this Group, papers and forecasts are provided by the Electricity Council's Commercial Department and the CEGB's Planning Department, and there is a composite view from the Area Boards. This process has the advantage of common background assumptions. The Board recognises, however, the disadvantage of a protracted timescale during which views may change, but considers that the organisation of the industry and the depth of analysis required are in part responsible for the length of the timescale. On the other hand, it points out that forecasts for the seventh year ahead will not usually be altered by unexpected changes in the short-term outlook.

4.9. Although the Department of Energy play no formal role in the industry's forecasting, they sponsor a Working Group[1] on Energy Strategy to discuss common assumptions. The Department ask the industries to show the sensitivity of medium-term plans to these assumptions. In 1962–63 the Government instructed the electricity industry to plan for a 4 per cent per annum rate of economic growth, and the CEGB has told us:

> 'the development of national economic planning by the 1964 Labour Government continued the emphasis on planning to meet high demand levels, thus ensuring that optimistic forecasts continued to be adopted'.

In the early 1970s formal Government advice was given, but the industries had discretion whether or not to follow it.

Forecasting methods

4.10. The CEGB's forecasts of electricity demand are built up around three broad sectors: domestic, industrial and commercial. It examines the likely total energy demand for sub-sectors within each of these, and then considers what electricity's share might be. The forecast of sales to the domestic sector is divided between appliance usage, and heating and cooking. The process begins by estimating the demand for 14 appliances, eg colour televisions and freezers, and using the Electricity Council data bank on ownership levels. It also takes into account Government projections of population and household formation trends. Forecasts of electricity demand from each type of appliance are then made, taking into account information about individual appliances becoming more efficient in use of electricity. In recent years the main source of growth in the domestic sector has come from the increased use of appliances. The CEGB makes estimates of when saturation of these markets will be reached.

4.11. As electricity faces competition from other fuels in the markets for space heating, water heating and cooking, the CEGB begins its forecasts for these by estimating the total demand for useful energy,[2] and then examines electricity's likely share. The Board has used relationships between demand for useful energy and consumers' expenditure in forecasting based on data since 1954, and recently it has modified these to take account of consumers'

[1] With representatives from the Department of Energy, the Treasury, Scottish Economic Planning Department, the Electricity Council, the CEGB, the SSEB, the UKAEA, the NCB, British National Oil Corporation and British Gas Corporation.

[2] Useful energy is that which a consumer enjoys—a coal fire, for example, only gives out about 25 per cent of its potential heat.

reaction to higher energy prices by installing additional insulation. Also regarded as important is the change in composition of the housing stock, as the age of a house can affect the amount of heat required for comfort. An upper limit to growth of demand can arise here, but because of an expected lower rate of economic growth the CEGB does not expect this to occur before 1987–88. Since 1973 electricity has not been price competitive for space heating, so the CEGB considers its share to be dependent on the rate at which households turn to other fuels, principally gas. It believes that this process will be largely complete by the end of 1987–88 in all areas where gas is available.

4.12. In the past the CEGB's forecasts of industrial demand distinguished only between iron and steel and the rest of industry, but it has found that the relationships established before 1973–74 between useful energy consumption and industrial production have broken down. It has, therefore, identified ten main groups of industries, and for each it estimates the link between output and demand for useful energy. This method requires the CEGB to forecast industrial production which it does using its own view of economic growth, and employs independent forecasts of the medium-term prospects of each industrial sector. Forecasts of useful energy demand from each industry sector are then made using the estimated relationships, modified by judgments on potential energy conservation. Electricity market share is based on judgments about future technology and major developments, such as private generating schemes. Only 10–15 per cent of electricity sales in this sector is for process heating purposes for which other fuels could be used, and over 70 per cent is for motive power and lighting. Therefore the Board does not consider relative price to be as important in determining demand as in the domestic sector.

4.13. The CEGB told us that it found accurate forecasting of electricity demand by the commercial sector difficult because of the diverse nature of the sector, and does not consider its present methods to be entirely satisfactory. The use of a relationship between useful energy demand and output for the whole sector has been shown to be too generalised, and attempts to examine the use of electricity in sub-sectors have been hampered by a lack of information. The Electricity Council is undertaking market research to improve the industry's knowledge and understanding. For the present the CEGB uses various methodologies, and takes for its forecast the result which it thinks most likely.

4.14. As a consequence of its studies and analyses of its customers, the CEGB does not believe total electricity demand during the next seven years will be very responsive to price changes. It has told us that it believes the overall price elasticity for electricity relative to the price of other fuels to be $-0{\cdot}1$; that is to say if electricity prices were to rise by 10 per cent and other fuel prices remained unchanged, then total electricity sales would fall by about 1 per cent. It also believes that in circumstances where the electricity price changes in line with other energy prices, the responsiveness of electricity demand would be less than this.

Forecasting peak demand

4.15. Using the methods described above the Board each year arrives at a forecast of total sales in each sector for the seventh year ahead. For investment planning, however, it also requires forecasts of peak winter demand. These are derived from a consideration of the likely trend of the system load factor, defined as the ratio of average sales to peak sales. The trend in the system load factor is reviewed on a disaggregated basis as changes in sectoral demands may increase or decrease the total load factor. For example, more widespread use of an appliance such as home freezers, which are operated throughout the year and round the clock, would increase the domestic load factor. The Electricity Council mounts a continuous programme of market research and statistical analysis to provide the basis for this forecasting.

4.16. Under the load management scheme certain industrial consumers agree to reduce their load on the system when requested by the CEGB, and are compensated by being exempt from peaking capacity charges. The size of this reducible load is subtracted from the estimated maximum demand.

Long-term forecasting

4.17. Because it must estimate the lifetime effects on system costs of major generation investment the CEGB needs to make demand forecasts for further ahead than seven years. By extrapolating the 'adopted' forecasts the Electricity Council forecasts for a further two years ahead and the CEGB for up to 12 years, and in addition both bodies collaborate with the Area Boards in the construction of 'scenarios' for longer periods. The last such exercise (in 1978–79) was based on high and low demand 'scenarios', and the CEGB is preparing another, to be completed in 1981. This will extend the low demand 'scenario' broadly in line with its present thinking, and will be used to test the robustness of long-term plans.

Forecasting record

4.18. Before 1973 forecasts were made for six years ahead extrapolating past trends of demand. Since 1974 the CEGB has developed the approach described in paragraphs 4.10–4.14 including a forecast of economic growth, and now forecasts demand in the seventh year ahead. Table 4.1 compares the estimates made of the growth of GDP by the Board's Planning Department with those which the Council agreed should be used as the basis for load forecasting, and with advice or agreed assumptions which came from Government sources. All have in the past consistently over-estimated the rate of GDP growth. Table 4.2 shows the CEGB's and the industry's 'adopted' forecasts for maximum electricity demand in the planning year, and it will be seen that all were consistently too high, with the CEGB being more optimistic than the industry.

4.19. The Board has told us that during the mid-1960s the importance of North Sea gas was under-estimated, and that more recent errors mainly result from optimism about general economic conditions. An analysis of the 32 per cent error in the 1974 forecast for 1979–80 shows that about two-thirds

TABLE 4.1 **Forecasts of growth in GDP and outturn (where possible)**

Date when forecast made	*Forecast for growth until*	*CEGB Planning Dept* % pa	ESI* *agreed* % pa	*Government† advice/agreed assumptions* % pa	*Outturn growth rate over 6 year period* % pa	*Over forecast of GDP in 6th year by CEGB*	*Over forecast of GDP in 6th year by ESI agreed*
March 1969	1974–75	Not made	3·2	3·0	2·3		5·4%
March 1970	1975–76	Not made	3·1	2·9	1·6		9·2%
March 1971	1976–77	Not made	3·2	3·4	1·5		10·5%
March 1972	1977–78	Not made	3·0	3·0	1·5		9·2%
March 1973	1978–79	3·0	2·6	3·0–3·5	1·7	8·0%	5·4%
July 1974	1979–80	3·0	2·3	2·5–3·0	1·1	12·4%	7·3%
March 1975	1981–82	2·8	2·7	Not given			
March 1976	1982–83	3·5	2·9	Not given			
March 1977	1983–84	3·0	3·5	Not given			
Nov. 1977	1984–85	3·5	3·3	3·5			
Oct. 1978	1985–86	2·2	2·6	2·8			
Oct. 1979	1986–87	1·7	2·0–2·4	2·8			
Feb. 1980	1986–87	1·2	1·0	1·1			
Oct. 1980	1987–88	0·5	1·0	0·9			

Source: The CEGB and Electricity Council.

* From 1973 to 1977 inclusive the underlying economic assumptions associated with the ESI's adopted load forecast were not explicitly agreed by Council: instead assumptions were prepared and recommended to Boards by the Council's Commercial Department.

† Until 1974 the Government advice came in the form of notes by the sponsoring Ministry to the Electricity Council. From 1977 until 1980 the advice of Government was given in the Working Group on Energy Strategy (paragraph 4.11), where assumptions are agreed. The column for these years shows the agreed assumptions. The advice/agreed assumptions were given a few months before the forecast.

TABLE 4.2 **Forecasts of maximum electricity demand* (GW) in England and Wales and outturn (where possible)**

Date when Forecast made	*Forecast for Demand in*	*CEGB Planning Department*	*ESI Adopted*	*Outturn*	*% Over Forecast by CEGB Planners*	*% Over Forecast of ESI Adopted*
March 1969	1974–75	54·1	53·2	41·9	29·1%	27·0%
March 1970	1975–76	57·1	54·0	41·1	38·9%	31·4%
March 1971	1976–77	58·7	54·0	42·0	39·8%	28·6%
March 1972	1977–78	60·6	55·0	42·4	42·9%	29·7%
March 1973	1978–79	56·8	56·5	43·8	29·7%	29·0%
July 1974	1979–80	58·2	56·5	44·1	32·0%	28·1%
March 1975	1981–82	53·7	54·0			
March 1976	1982–83	52·5	52·0			
March 1977	1983–84	51·0	51·5			
Nov. 1977	1984–85	53·0	52·0			
Oct. 1978	1985–86	50·9	50·6			
Oct. 1979	1986–87	48·9	50·3			
Feb. 1980	1986–87	48·5	46·8			
Oct. 1980	1987–88	45·3	47·5			

Source: The CEGB

* In 'Average Cold Spell' Conditions.

of this error (over 20 percentage points) arose from over-optimism about future GDP (the 1974 forecast of GDP in 1978–80 was 12·4 per cent too high, indicating that general economic conditions were believed to be a very important influence on electricity demand). Most of the rest of the error was accounted for by over-estimation of future energy demand; less than four percentage points was over-estimation of the share to be taken by electricity. The CEGB remained optimistic about the economy's prospects after 1974–75, and only started to revise its forecasts downwards in October 1978.

Lessons from past forecasts

4.20. The CEGB has told us that it has learnt a number of lessons about its forecasting. These are:

(i) The need to be thoroughly realistic about United Kingdom economic prospects for the medium-term. In retrospect its economic forecasts have been optimistic.

(ii) The significance of energy conservation; the period since the energy price rises of 1973–74 has provided valuable evidence on this, which is now being incorporated in the CEGB's forecasts.

(iii) The trend method of forecasting employed prior to 1973 has been discontinued as it is no longer considered a useful approach. However, the CEGB never relied on this completely, regarding it as a benchmark against which the forecasts by the Area Boards and Electricity Council could be examined.

4.21. Recent forecasts by the Board's Planning Department reflect the current economic recession. In October 1979 it pressed for a reduction of 5 per cent in the previous year's 'adopted' estimates. Although that was not accepted by the Load Forecasting Group, the CEGB based its investment appraisal choice in the 1979–80 Development Review on both forecasts, using its own for the calculation of the planning background (see paragraph 5.6). In February 1980 the medium-term load estimate was revised downwards by the Council, but because of the short notice the Board was not able to make a complete re-appraisal, with the result that the Board's forecast was higher than that eventually adopted by the Council.

Comparisons with other forecasts

4.22. As forecasting involves judgment as well as method we thought it useful to examine the CEGB's record by comparison with the forecasts of other bodies made at about the same time.

4.23. We asked a sample of large corporations, both publicly and privately owned, for the medium-term forecasts of GDP they had made in the past. We received seven replies from the private sector and four from nationalised industries. One of the forecasts in 1975 was for four years ahead; the remainder were for five years ahead or longer. We asked where possible for forecasts made at the end of the year, but some of our respondents had forecast only earlier in the year. Table 4.3 compares these forecasts with those of the CEGB's Planning Department and with the assumption agreed by the Load Forecasting group (see paragraph 4.8).

TABLE 4.3 **Forecasts of medium-term growth in GDP**

Forecast made in	*CEGB Planning Department % per annum*	*ESI agreed % per annum*	*Average of private sector % per annum*	*Average of public sector % per annum*
1975	(March) 2·8	2·7	{ 2·3 }	{ 2·4 }
1976	(March) 3·5	2·9		
1977	(March) 3·0			
	(Nov) 3·5	(Nov) 3·5	2·5	2·6
1979	1·7	2·0–2·4	1·7	1·4

Source: Monopolies Commission

4.24. This shows that in the mid–1970s the Planning Department was forecasting significantly faster growth in the economy than the average of either public or private sector corporations in our sample, but by 1979 its forecast was only a little above average. The ESI adopted forecasts in both 1977 and 1979 were significantly more optimistic than our sample's average.

4.25. Since 1977 the Department of Energy have published annually two 'scenarios' for the year 2000, based on high and low energy demand. Medium-term projections are made for different purposes including participation in the work of international bodies such as the IEA and the EEC. The CEGB's long-term forecasts of electricity demand were not noticeably higher than the Department's projections. The Science Policy Research Unit of Sussex University (SPRU) published long-term demand forecasts in 1978 that were a good deal lower than the industry forecasts at that time. The main reasons for the difference were a less sanguine view of economic prospects, and greater scepticism about electricity's capacity to hold (or penetrate) major domestic and industrial markets. Various other groups and individuals have, in recent years, put forward forecasts of electricity demand, and many of these have been significantly lower than the ESI's. These other forecasts were typically based upon much more vigorous energy conservation policies than assumed by the industry and expected a larger conservation effect than has so far taken place.

The costs of over-forecasting

4.26. Over-forecasting of electricity demand has affected the CEGB's costs through inducing the ordering of plant to support a load which in the event did not materialise. Taking into account the de-commissioning of old plant to reduce costs in the light of lower demand growth, and the commissioning of new capacity ordered in the 1960s, it is possible to estimate whether the CEGB would have needed to place any further orders if it had been able to forecast without error. We do not not wish to suggest that such a feat was possible, but rather consider this a suitable way to assess the costs of over-forecasting.

TABLE 4.4 **Demand, capacity and plant margins in CEGB, 1970–80**

Year	*Max demand met during year*	*Output capacity at beginning of year (excluding orders made after 31 March 1970)*	*Resulting plant margin*
1970–71	38,619	46,857	21%
1971–72	39,925	49,281	23%
1972–73	40,639	54,322	34%
1973–74	39,624	56,427	42%
1974–75	40,973	58,026	42%
1975–76	41,353	58,523	42%
1976–77	42,110	58,677	39%
1977–78	42,803	56,263	31%
1978–79	44,102	56,224	27%
1979–80	44,225	55,945	26%

Source: The CEGB

Table 4.4 shows that during the decade 1970–80 there would have been sufficient capacity to meet demands without completing any new stations. Even between 1978 and 1980 when the resulting plant margin was less than the 28 per cent planning margin (see paragraph 4.42), there was enough plant to meet the generation security standard (see paragraph 4.63 on the operating reserve margin). In fact only about 180 MW of plant ordered during the 1970s was commissioned before March 1979 (see Chapter 12) and had the first four AGRs been commissioned on time, the CEGB would have been embarrassed by even larger surpluses of plant. Furthermore, in 1976–77 the Board de-commissioned about 2·7 GW of old plant before it was life-expired.

4.27. With perfect foresight the Board would not have needed to order the stations at Isle of Grain, Ince B, Littlebrook D, and the 1200 MW of main gas turbines when it did. (Dinorwic, a pumped storage station, and Drax completion were also ordered during the decade, but were not expected to be commissioned before March 1979.) The three large conventional stations alone were estimated to cost about £2,500 million[1] at March 1980 prices, excluding interest during construction. The oil-fired plants will be low in the merit order, and gas turbines will offer no system savings. On the other hand the second half of Drax, when commissioned, is expected to give considerable system savings.

The Bulk Supply Tariff

4.28. The Bulk Supply Tariff (BST) is the tariff for sales by the CEGB to the Area Boards which sales accounted for about 98 per cent of the CEGB's income in 1979–80. The remaining 2 per cent represented direct sales to consumers: the CEGB has received Ministerial permission to sell directly only in the cases of the United Kingdom Atomic Energy Authority, British Nuclear Fuels Ltd and Anglesey Aluminium Ltd, besides being empowered by statute to sell to British Rail and London Transport.

[1] See Appendix 25. These figures are based on the estimated final costs at scheme base date prices, updated by using the CSO implied index of total Home Costs.

4.29. The CEGB has told us that it charges BR and London Transport at BST rates, with a small surcharge to compensate it for some additional costs of supply to these users. In the case of UKAEA and BNFL, the CEGB is essentially providing a transmission route for the electricity that these two bodies generate and consume, but the CEGB has told us that they pay charges on the balance, related to the BST. Anglesey Aluminium, however, bought a share in Dungeness B's output when the project was planned, and pays an annual charge related to what this AGR station's costs would be were it now on-load.

4.30. The CEGB states that the primary objective of the BST is

> 'to act as the main commercial instrument of the CEGB by indicating when electricity is cheap and when it is dear. By sharing this information with consumers, the Board seeks to encourage economic growth of load'.

The term 'consumers' refers to the Area Boards, but it is intened that they should pass the structure on to final consumers. The 'cost information' is intended to encourage users to alter the extent and timing of their demands upon the CEGB's system in such a way as to create a structure of demand which keeps costs down. The choice of tariff structure is therefore of considerable relevance to our inquiry.

4.31. The Board states that to meet this primary objective and to recover its costs, it has 'drawn up [the BST], as far as is practicable, on the basis of marginal costs'. When it announced the 1980–81 BST, however, it added that

> 'in fact at present the income that would be yielded by a fully marginal tariff would yield a greater profit than is consistent with the financial objectives set to the Board by the Government. In consequence the BST is set slightly below the level of long run marginal costs'.

An adjustment was introduced into the 1980–81 BST so that the whole tariff would retain the marginal cost structure, despite its level being below long run marginal costs. However, in the light of lower than expected demand in 1980–81, the CEGB has re-assessed its tariff calculations and now estimates that the BST is at the level of long run marginal costs.

4.32. The BST is a multi-part tariff, ie separate charges are levied for different aspects of the service. The Service Charge is levied for being connected to the system, Demand Charges for the capacity taken up, and Energy Charges for the actual power supplied. The Service Charge raised only 0·6 per cent of the CEGB's revenue from Area Boards in 1979–80, whereas the Demand Charges raised 22·4 per cent and the Energy Charges the remaining 77 per cent. The Board states that the Energy Charges of the BST are based upon the effect of a small change in demand on the CEGB's costs; if a small change in demand is expected to persist, it alters capacity requirements, and the effect of this on costs in the long run is reflected in the Demand Charges of the BST. Thus the Board has divided its cost structure into two main sections, and bases its tariff upon:

(i) Operating cost estimates, which are intended to indicate to Area Boards that it is more costly for CEGB to provide electricity to a user at times of maximum load because less efficient plant must be used, hence raising the fuel burn per kWh sent out. The Energy Charges are based upon these estimates.

(ii) Capacity cost estimates, ie estimates of cost to the CEGB of meeting a permanent change in demand pattern if it persists in the future.This cost in the longer term is the cost when the mix of plant can be altered by investment or plant retirement. The Demand Charges are based upon these estimates.

4.33. In Appendix 12 we explain how the estimates of marginal costs are calculated, drawing attention to the Demand Charges, for which the Board faces the difficulty of judging the relevant long run costs. We set out what judgments are made, and show how the 1980–81 BST was derived from these estimates. We also explain the method by which capacity requirements are attributed to Area Boards, and the maximum and minimum charges. Finally we explain the Fuel Cost Adjustment.

The BST's effectiveness in reducing costs, and scope for improvements

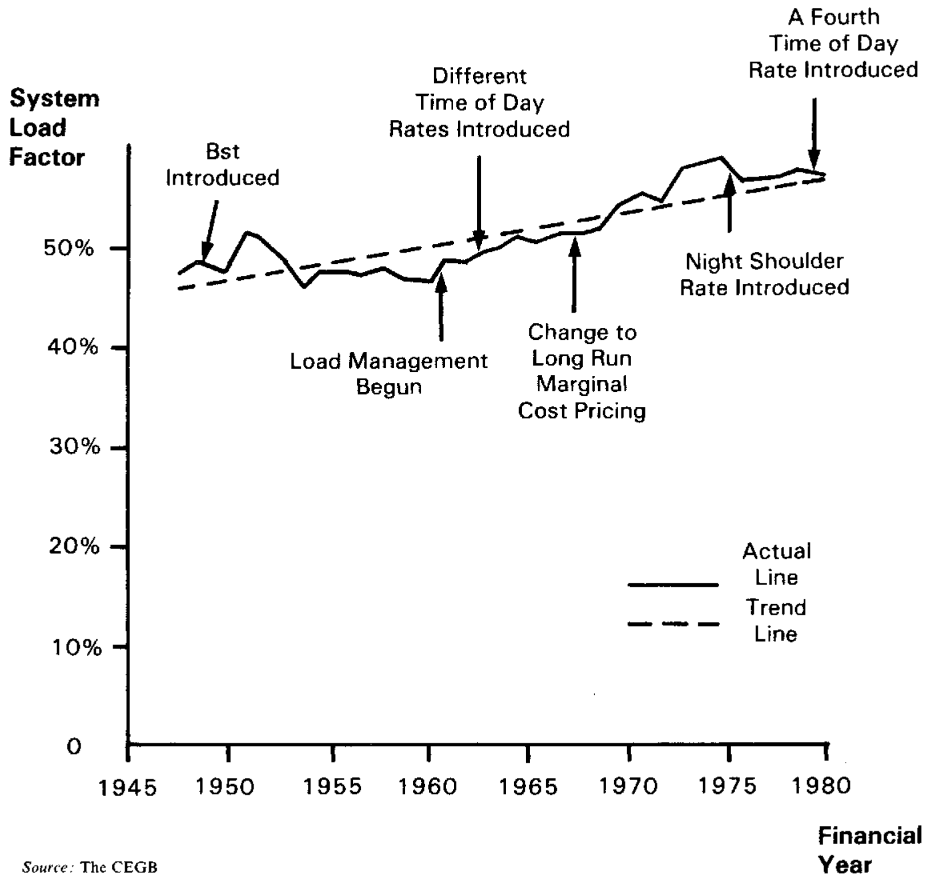
4.34. One measure of the BST's effectiveness in altering the structure of demand and hence reducing costs is the trend of the system load factor, which is defined in paragraph 4.15. The Board told us that, in its opinion, a higher planning margin is needed as the load factor rises because the incidence of breakdowns is higher than at a single peak. Nevertheless improvements in the load factor represent more intensive use of plant, whose economic benefits the Board hopes the BST shows. Figure 4.1 relates changes in the BST to changes in the system load factor over the last 30 years. It shows that the load factor has been rising (at an average rate of just over 0·3 percentage points a year), and suggests that some of the improvement in the system load factor may result from the increasing sophistication and complexity of the BST over the last 25 years.

4.35. We asked the CEGB whether a different tariff structure might further improve the system load factor, and hence reduce costs. For example, a doubling of the peak rate relative to other energy charges could be expected to flatten the load curve. However, the Board argues that to charge Area Boards more at the peak than the long-run marginal costs they impose upon its system would be to cross-subsidise in favour of some consumers, or alternatively to tax peak consumers. The Board considers that if certain consumers prefer to increase their consumption at the peak, and are prepared to pay the extra cost, then no additional penalty can be justified.

4.36. Under the present BST, Demand and Energy charges are levied on Area Boards on the basis of capacity taken up and power consumed, which are measured in terms of kW and kWh respectively. The Capacitor Manufacturers' Association has suggested to us that electricity supplies should be charged to Area Boards on the basis of the potential energy supplied, measured in terms of kVA. The CMA argues that such charging would encourage the more economical use of power, by penalising those users who do not make full use of the potential energy supplied. The CMA suggests that if Area Boards in their turn charged on a kVA basis, then it would pay some users to install more capacitors and hence make fuller use of the energy supplied.

FIGURE 4.1

System Load Factor



Source: The CEGB

4.37. In response to the views of the CMA, the CEGB has pointed out that the Area Boards' consumption is currently metered at the points where the 132 kV supplies are transformed down to 33 kV. These were the bulk supply points up to 1970 when responsibility for the 132 kV system was transferred from the CEGB to the Area Boards. The Board states that the existing metering equipment at 132: 33 kV transformation points would not give a sufficiently accurate estimate of Area Boards' kVA consumption at the present bulk supply points (where the 400 kV or 275 kV supplies are transformed down to 132 kV). Changing the basis of the BST from kW/kWh to kVA would therefore require the Board to invest in additional metering equipment at a cost of some £20–£30 million. The cost of installing additional capacitors and switching devices elsewhere in the system would also have to be set against any system benefits.

4.38. The Board also told us that it keeps such power losses under review, and that Area Boards are told if these are becoming unacceptably high. Furthermore it pointed out that the service charge element of the BST includes the cost of providing and maintaining transmission equipment, the quantity of which is related to the Area Boards' use of power. However, the service charge element accounts for less than 1 per cent of the revenue raised by the BST. It adds that, whilst it is true that greater use of capacitors by electricity consumers would save power, it might also risk the stability of the generating system. It considers that the current trade off between cost and risk is satisfactory. Indeed the Board draws attention to the possibility that kVA charging could discourage the use of capacitors in some cases (particularly when the system is unstable) and considers a kVA tariff 'too blunt an instrument to deal with widely differing conditions'.

4.39. Finally, the Board has told us that it is investigating whether or not cheaper metering and switching equipment could be developed. It also expects the benefits from improving system load factors to increase over time. It therefore believes that whilst there is not a strong case for altering the BST in the way suggested by the CMA at the moment, the balance of advantage might eventually shift in favour of a kVA-based tariff and it is keeping the matter under review.

4.40. We asked the CEGB whether, in its view, the BST structure was adequately passed on by the Area Boards to final consumers. The Board told us that the major piece of cost information it wishes consumers to know is that electricity is cheaper to produce at night than during the day; that in so far as the Area Boards' tariffs convey this information the BST is adequately passed on; and that 'where the message is more complex, the Area Boards apply it where feasible'.

4.41. We consider that the important question is whether Area Boards' tariffs influence the habits of consumers in the direction desired by the CEGB. We have not investigated Area Boards' tariffs, but such material as we have seen suggests that there is a discrepancy between the CEGB's intention in setting the BST and the outcome. We are unable to comment on the extent to which tariffs for industrial and commercial users pass on the BST structure; we can only note that there are many different tariffs of varying complexity.

However, we observe that a large proportion of electricity sales is to domestic consumers paying a single rate, and that even sales to domestic consumers who take advantage of the 'Economy 7' tariff are unaffected by any charge for power taken at the daily peak.

The security of supply standards and the planning margin

4.42. The Electricity Supply Regulations, 1937 made under the Electricity (Supply) Acts, 1882 to 1936 provide:

> 'From the time when the Undertakers commence to supply energy through any distributing main, they shall maintain a supply of energy suffficient for the use of all consumers for the time being entitled to be supplied from that distributing main; and that supply shall be constantly maintained without change of the neutral conductor unless otherwise allowed by the Electricity Commissioners and subject to such terms and conditions as they may impose.'

Under the Regulations, the supply may be discontinued in defined circumstances, including emergency. In 1948 the obligations of the Undertakers were transferred by the Electricity Act, 1947 to the Electricity Boards (the Area Boards, the CEGB and the two Scottish Boards), and under a statutory instrument (SI 1769/1948) the powers of the Electricity Commissioners were assumed by the Minister of Fuel and Power.

4.43. The industry has attempted to meet this obligation without imposing unreasonable costs on electricity consumers by defining security standards for generation, and for the transmission and distribution networks. The generation standard requires the Board to hold capacity additional to the expected level of demand. The extra capacity planned for when investment decisions are taken is called the 'planning margin', and currently is 28 per cent. The transmission security standard affects the requirements for reinforcements to transmission lines, and also in some cases operation of generating plant out of merit order is called for. Although we are not able to state what are the costs of meeting the security standards, there can be little doubt that they are substantial (see paragraph 4.51). Decisions on the security standards and their interpretation are made in the Electricity Council.

4.44. The industry expresses the standard it has adopted (as described in a 1978 Electricity Council paper) as follows:

> 'it is acceptable to plan on the basis that for three or four winter peaks in every 100 there will be disconnections through shortage of generating plant, ie after allowing for 7½ per cent load reduction through voltage and frequency reductions. Implicit in this is that there will be some form of load shedding, through voltage or frequency reductions or disconnections, for about twenty winter peaks per century'.

Thus, in three or four winters in every hundred there will be disconnections during the period of highest demand because of shortage of generating plant. During those winters there would most probably be other disconnections because of variations in plant availability. On average a winter, when there is shortage of plant to meet the peak winter half hour's demand, will be one when disconnections of some consumers will be necessary for 50 hours.

The number of consumers disconnected in these periods may be small, but the loss of supply if averaged for all consumers connected would be about 120 minutes over the winter.

4.45. Between 1958 and 1976 the estimates of risks used to derive the planning margin (see Table 4.6) were such that the standard could be consistently interpreted as three winters per century disconnection at the peak, and 24 winter peaks per century when voltage or frequency reduction would be necessary. However, a revised judgment of risks has led to slightly different values which still 'broadly meet' the standard; this is now a higher risk of disconnection at four peaks per century, and a lower risk of frequency and voltage reduction at 19 peaks per century. This revision is now used for all planning purposes.

4.46. In the time available to us we have not been able to examine the implications for investment appraisal of the security standards for the CEGB's transmission networks.

Security of supply and loss of power—the historical record

4.47. Table 4.5 shows the average length of the time of disconnections per annum that each connected consumer suffered, arising from various causes, including interruptions to supply arising from industrial disputes (both in the power and coal industries), of which there were four during the last 15 years. An interruption is defined as 'any event that caused loss of supply to one or more customers', but because of the nature of the disruptions during the 'Three Day Week' data comparable to other years has not been provided by the Council for the year 1973–74.

TABLE 4.5 **Average minutes loss of power per customer per annum and causes (England and Wales)**

	CEGB		*Area Boards*			
	Generation shortage	*Other* (mainly transmission)*	*Faults (on ABs' systems)*	*Pre-arranged outages*	*Industrial disputes (approx)*	*Total*
1965–66	5·2	3·4	64·4	31·0	0	104
1966–67	0	3·9	64·9	28·2	0	97
1967–68	0	1·8	70·1	20·9	0	92·8
1968–69	0	4·1	74·4	17·7	0	96·2
1969–70	0	3·2	68·8	13·0	0	85·0
1970–71	0	0·6	53·2	11·8	150	215·6
1971–72	0	1·2	60·3	11·9	3,000	3,073·4
1972–73	0	3·6	46·9	13·5	0	64·0
1973–74	0	0·0	97·4	15·3	No equivalent data	Not available
1974–75	0	0·1	60·0	17·1	0	77·2
1975–76	0	1·2	112·4	19·1	0	132·7
1976–77	0	0·2	67·0	19·0	0	86·2
1977–78	0	0·2	76·3	18·0	120	214·5
1978–79	0	0·7	62·6	21·0	0	84·3
1979–80	0	0·1	56·6	22·4	0	79·1

Source: Electricity Council

* After 1972–73 all 132 kV faults are included in the Area Board figures following change of ownership.

4.48. The table indicates that industrial disputes have been the major cause of loss of supply during the last 15 years. The Council has told us that supply interruptions because of shortage of generating plant have not occurred since 1966, and that the number of occasions when load had to be shed by voltage or frequency reduction for this reason has fallen from an average of over 90 per year in the period 1950–51 to 1954–55 to less than one a year in the period 1975–76 to 1979–80. During the last 30 years disconnections, because of plant shortage, were necessary at the estimated winter peak half-hour in 1950–51, 1952–53, 1955–56 and 1963–64.

Reviews of the generation security standard

4.49. The interpretation of the statutory obligation to maintain supplies is a matter which has caused difficulties; the industry has devoted considerable effort in attempting to resolve them in a reasonable manner. Difficulties arise because, although it is accepted it would be prohibitively expensive to guarantee 100 per cent reliability, it is not clear how much of a shortfall would be appropriate. During the 1970s there have been two reviews within the industry of the standard associated with increases in the planning margin, and a joint Government/Industry study. The first industry study of the standard was in 1970, when the CEGB proposed that the planning margin should be raised from 17 per cent to 23 per cent. As a result the margin was raised to 20 per cent and the security of supply standard remained unchanged. The second industry study, at the end of 1978, reviewed the rise in the planning margin from 20 to 28 per cent (introduced in early 1977) and the security supply standard remained unchanged.

4.50. In these reviews two strongly held opinions on how to determine an appropriate standard can be distinguished. The majority in the electricity supply industry believe that the correct approach is to consider expenditure on security as something in the nature of an insurance premium. If the 'premium' paid is expressed per kWh supplied it appears to be very small. The second approach is to consider changes in the standard in terms of costs and benefits; this was described in the 1970 review as follows:

> 'It would be wrong for the supply industry to spend less on security than the value of the loss, damage or inconvenience suffered by consumers from an interruption of supply, and equally, it would be wrong to spend more.'

4.51. In discussing the alternative approaches the 1978 review stated:

> 'The net annual cost of small variations in the security standard would be a fraction of 1 per cent of the total annual costs of producing and distributing electricity, so that consumers would barely notice in their electricity bills the savings from reducing security standards. Yet they would certainly notice the increased frequency of disconnections. On the other hand, and with equal validity, it can be stated that the cost of the marginal kWh which can be supplied at present security standards is about £5/kWh based on disconnections only.'

This calculation was made on the basis of the estimate at the time of the NEC of gas turbine plant at £10/kW per annum. The last gas turbine plant served to prevent the need for two hours of disconnections, and hence could be costed at £5/kWh. It also prevented ten hours of voltage and frequency reduction, but these were excluded because there was dispute about the measurement of the disruption experienced by consumers as a result of such load shedding measures.

4.52. To set against this there are the benefits which accrue to consumers from not being inconvenienced by loss of supply. The review noted earlier studies on benefits which estimated them at about £1·30/kWh. It added that 'there are obvious difficulties in making such estimates . . . [although they can] . . . be supported by the very few actual calculations that have been made of the effects of disconnection'. One indication of the divergence of views inside the industry is given in the 1970 review where the majority of the working party favoured an overall reduction in the standard because of the increased costs of maintaining it. However, this view was not accepted by the Electricity Council.

4.53. The standard was not changed after the 1978 review of the increase in the planning margin from 20 to 28 per cent. The position then was described in the review paper as follows:

> 'In view of the strong differences of opinion on some of the issues . . . it is difficult to reach a conclusion on security standards which will command general support. There seems to be no effective way of giving consumers the opportunity to choose the standard of security they are prepared to pay for—indeed, within the industry there is debate about the right way of presenting the costs involved. However, as a tentative conclusion, it seems difficult on any rigorous analytical basis to justify the costs of the present security standard in comparison with the benefits consumers are likely to receive. Nevertheless, there is no external view (apart from the Treasury) which criticises the standard as excessive; such criticisms as are made, and these can be strong when there is an actual shortage of capacity, are that security standards should be improved.'

The Electricity Council has told us that it still believes there is no analytical method of determining a standard which would command the support of all its members.

4.54. In 1974 the Treasury and Department of Energy produced a study called the 'Economics of Reliability in Electricity Supply' based on a cost/benefit approach. It was followed by the establishment of a joint working group of officials from the Treasury, Department of Energy, Electricity Council and the CEGB which examined the calculations in the study, and considered the feasibility and problems of consumer surveys/experiments as means of determining consumers' appreciation of the cost of failures of supply. The report of the working group

> 'acknowledged that a substantial element of judgment is involved in the setting of security standards and the planning margin. Implicitly or explicitly, these judgments are made whatever approach is adopted. Thus, in considering the marginal cost benefit approach, a basic judgment is required as to what weight to give this approach as compared with other considerations, but further to this . . . even detailed application of this cost benefit approach must inevitably involve a number of judgments . . .'

However, the group drew attention to the very wide difference in the security standard and planning margin which resulted from the two approaches, and suggested these be discussed at a higher level. The CEGB has told us that both the working group report and the calculations of marginal cost/benefit in the 1978 review demonstrate that quantification of the costs and benefits has been attempted.

4.55. The Treasury have told us that they and the Department of Energy

> 'discussed with the CEGB on a number of occasions the Board's planning margin and security of supply standard. Treasury officials' view has been that decisions on both the margin and the security standards should as far as possible be taken on the basis of quantification which reflects costs and benefits.'

The Treasury recognise that quantification is extremely difficult, and this is an area where costs cannot be adequately reflected in tariffs, so the price mechanism cannot be used to determine consumer preferences. Nevertheless they believe 'that it would be worthwhile to attempt quantification for both the standard and the margin'.

The Department of Energy have told us that the Government has not formally endorsed the 28 per cent planning margin. While acknowledging the difficulty of arriving at any objective quantification of the costs and benefits of the standard and the margin and the element of judgment involved in setting them, they share the view that the attempt at quantification would be worth making. They regard the margin as a matter for continuing discussion with the industry.

The planning margin and plant margins

4.56. In order to meet the security of supply standard, the CEGB must hold available plant in excess of expected demand. As well as the planning margin, which is the requirement for capacity in seven years' time, ie that which investment can affect, there is the operational plant margin. The Operations Department plans at all times to hold spinning reserve, which is plant heated up and available to go on load should any major higher merit unit fail, or demand increase sharply and unexpectedly. The commissioning of pumped storage plant reduces the need for spinning reserve, but instead requires that enough power is stored to give the necessary operating margin. Looking further into the future, the Board plans to have a reserve plant margin for two years ahead. Old plant near the end of its life is kept available for operation to cope with a sudden change in demand or in the availability of other plant. The two year horizon used for this operational planning results from the timescale for plant closure—one year is allowed for consultation, followed by a year's formal notice.

The derivation of the planning margin from the security standard

4.57. The CEGB determines the planning margin after consultation with the Electricity Council, and has told us that in this consultation its views 'naturally carry considerable weight'. Thus the Board's Planning Department has the task of estimating how much investment is needed to guarantee that at least as much plant is available as is required to meet the security standard.

Some plant margin is needed because availability is not 100 per cent (because of repairs etc). Risks occur because both plant availability and demand cannot be forecast with any certainty. Estimates of the future behaviour of four factors (seven years ahead) affect the size of the margin. These are:

(i) the expected availability of plant during periods when demand is near its peak, currently estimated to be 85 per cent;

(ii) the expected variation in plant availability at that time, currently estimated to be a standard deviation of 3·75 per cent;

(iii) the expected variation in forecast peak demand because of weather variation, currently estimated to be a standard deviation of 3·8 per cent; and

(iv) the expected variation in forecast peak demand because of forecasting error, currently estimated to be a standard deviation of 9 per cent.

The choice of all these estimates is based upon analysis of past outcomes which influences but does not determine the judgments of the CEGB and the Council.

4.58. Appendix 13 explains how the planning margin is calculated. The result is the 28 per cent margin. Table 4.6 compares this with the planning margins used before 1977, and gives the dates when the estimates of the four factors changed.

TABLE 4.6 **Changes in the planning margin and the four factors**

Period	*Planning margin*	*(i) Expected winter peak availability*	*(ii) Expected variation in winter peak availability*	*(iii) Expected variation in demand because of weather*	*(iv) Expected variation in demand because of forecasting error*
	%	%	%	%	%
1959–62	14	90	3	2·4	2·7
1962–64	14	90	3	3·3	2·7
1964–70	17	90	3	3·8	6
1970–71–1976–77	20	88	3	3·8	6
1976–77 (to date)	28	85	3·8	3·8	9

Sources: The CEGB and Electricity Council.

Investment and the planning margin

4.59. The CEGB has told us that the planning margin does not currently influence investment decisions as these are not being decided on the basis of need to acquire new plant to meet demand but on other considerations. Moreover, during the last decade two major orders, for Ince B and Drax completion, were made at the Government's request 'in advance of need' and 'overrode decisions that might have been taken simply by reference to the planning margin'. Indeed, the CEGB is not sure at this stage to what extent the margin will directly influence future orders of power stations because:

> 'The CEGB analysis of the economics of nuclear power suggests that there are good prospects, within a wide range of sensitivities . . . that additional nuclear plant should . . . be introduced on to the Board's system irrespective of the value of the firm capacity thereby added'.

Apart from this cost-saving consideration, the CEGB also considers that the planning of new capacity must take into account the likely hump in investment requirements in the 1990s as older plant reaches the end of its useful life. Old plant can in the meantime be closed to minimise costs. Therefore the Board concludes:

> 'For these reasons, the precise value of the planning margin is currently irrelevant to immediate ordering decisions even though it may continue to be relevant in the long run to later plant ordering decisions.'

The costs of the planning margin

4.60. The planning margin used for past ordering decisions for plant affects current costs, but it is not easy to establish how different present costs would be had there been a lower margin. This is because new plant displaces older less efficient plant in the merit order, and therefore offers system savings which offset part or all of its costs. Even a newly commissioned oil plant, although relatively low in the merit order, will displace some less efficient plant. The CEGB has told us that changes in the margin can be costed, but not the margin itself. If no margin of plant was held, then annual average availability of plant of 72 per cent and winter peak availability of 85 per cent would imply considerable supply shortages. The Board estimates that if planned outages of plant for annual overhaul could exactly match seasonal demand and all plant performed as estimated a day ahead, then load reductions (voltage and disconnections) would be necessary during 1,700 hours each year, given current demand. In practice this figure could be as high as 2,300 hours. The CEGB has therefore stated that it considers a situation in which no margin was held would be unacceptable 'both in terms of our statutory duty and public acceptability' and cannot therefore calculate the cost consequences. However, it has calculated the cost effects of changing the margin on what it calls an 'asymptotic basis' so as to allow for the system savings of new investments when the plant mix is not optimal. It argues that if, in the long run, say in the period 2000–2015, the mix is optimal, then all new plant will have an NEC similar to that of gas turbines or other similar low capital cost, high running cost plant. The NEC of gas turbines now is therefore taken to be the annual cost of a kW of plant. On this basis the CEGB has told us that the 1977 increase in the margin from 20 to 28 per cent was expected, at the time, to add about 2 per cent to the average BST. This was calculated using the then 10 per cent discount rate. It is currently estimated that a return to a margin of 20 per cent would reduce the requirement for investment in the long run by about 4½ GW. Using an NEC of gas turbine plant (based upon the 5 per cent Required Rate of Return—see see paragraph 5.9) of £22/kW per annum at March 1980 prices the cost saving would be about £100 million a year. In the middle of this period total annual CEGB costs are estimated to be about £9,000 million a year, implying an average BST price of three pence/kWh at March 1980 prices. The reduction in the margin would therefore reduce the average BST price by about 1 per cent. If the CEGB's plant mix is not as far from the optimum as its NEC calculations suggest, then cost savings of this order would be realisable much sooner, probably during the 1990s.

Future changes in the planning margin

4.61. The CEGB has told us that:

> 'before it [the margin] becomes a real factor again there will need to be a fairly significant review of all the elements that are going into it, and we shall be doing this . . . this year as a forerunner, primarily because the world does not stay still. The rate of growth [of load] is different and this may introduce some changes. Our availability performance is changing.'

We were told that 'it could be too large, but to some extent that is anticipating the studies which will be made'. This is so 'for a variety of reasons, including . . . our achievement of better plant availability performance'. However, the CEGB does not believe the margin was too high in the past.

The generation security standard, plant margins and costs

4.62. Although in present circumstances the CEGB does not consider it needs to order new plant on capacity grounds, the generation security standard continues to affect its decisions about the rate of de-commissioning of old plant and about operating procedures (such as the need to hold spinning reserve). This is because the operating plant margins described in paragraph 4.56 are derived from the standard.

4.63. The reserve margin for two years ahead (which is the minimum time in which a closure decision can be implemented) can be expressed in either gross or net terms. The net margin is the margin of plant expected to be available to go on load at any time. The CEGB has told us that the reserve margin is currently a requirement to keep about a 4 per cent net surplus, which is equivalent to a gross margin of over 22 per cent. This is because average plant availability is estimated to be 85 per cent, ie 117·6 MW of gross plant must be held to achieve an average of 100 MW available. Since the CEGB requires in net terms 104 per cent of maximum demand, it must hold $1{\cdot}176 \times 104$ per cent $= 122{\cdot}3$ per cent. This figure is lower than the planning margin because future demand two years ahead is considered less uncertain than in the seventh year. Every 1 percentage point reduction in the 22 per cent reserve margin would, on the basis of a maximum demand of 45 GW and a net avoidable cost of deferring plant retirements of £10 per kW per annum, save over £3·5 million per annum. The calculation of the necessary net margin is undertaken using the same methodology as the planning margin and, except for the estimate of forecasting error, estimates informed by similar judgments. Thus if for any reason the Board were to revise downwards its judgments as to the necessary allowance for any of the parameters, de-commissioning could be accelerated and a cost saving achieved after two years. The same would be true if the industry were to decide to reduce the security standard.

Conclusions

Demand forecasting

4.64. In paragraphs 4.18 to 4.27 we have examined the forecasting record of both the CEGB and the ESI. We note that both have been seriously inaccurate and that this has encouraged unnecessary or premature orders for new plant. These orders have increased costs. In paragraphs 4.10 to 4.17 we have examined the CEGB's current methodology and the way in which it arrives at its judgments, particularly on the future growth of Gross Domestic Product. Its approach now reflects the lessons of the past and, given the state of the art, we consider it to be sound.

Bulk Supply Tariff

4.65. We have examined the structure of the BST in paragraphs 4.28–4.41 and Appendix 12. The Board has told us that the structure of the BST is derived from an application of long-run marginal cost principles modified as necessary in the light of its financial targets.

4.66. We are concerned that the Demand Charges in the BST do not reflect a fully consistent application of long-run marginal cost principles. Specifically the Board has told us that the basic capacity charge is determined by reference to the expected long-run marginal costs in conditions at some point in the future when an optimal mix of generating plant is expected to exist. The Board has told us that it does not expect to achieve this until about 30 years hence. By contrast, the basis for the peaking capacity charge is an interpretation of long-run marginal costs reflecting the development of the Board's system over the next 10 to 15 years. We believe that such inconsistency in the application of the Board's preferred pricing principle creates the danger that over time the basis of the BST will become arbitrary. If the Board continues to use long-run marginal costs as the basis for setting the BST, we recommend that the Demand Charges should be based on the Board's plans for the development of its generation capacity over, say, the next 10 to 15 years, and not on the expected circumstances of some remote future date. We would add that if the Board adopts this course of action, it should also publish information about the direction in which the Board expects the BST to alter over time.

4.67. We also recommend that the Demand Charges should be based on central rather than 'basic' estimates of NEC's (see paragraph 5.163) because the 'basic' estimates may give a quite misleading impression of the costs which the Board is likely to incur, for reasons we discuss in Chapter 5.

4.68. We do not think that the influence which the Board wishes to exert through its tariffs is adequately reflected in Area Board tariffs. We draw particular attention to the absence of differentiation by time of day in the tariffs for many domestic consumers. It should be the responsibility of one authority within the ESI as a whole to ensure that tariffs do exercise appropriate effects on consumer behaviour. We also believe that the CEGB has been less concerned than it ought to be about the impact of its tariffs on final consumers, possibly because of the divided responsibility between itself and the Area Boards. At the very least, this points to a need for more effective consultation between the CEGB and the Area Boards and, in this context, we welcome that part of the Secretary of State for Energy's recent statement on the industry's organisation in which he drew attention to the need for more co-operation between the Boards in the setting of tariffs. However, we also hope that the re-unification of the industry is not an entirely closed issue.

The generation standard and planning margin

4.69. In paragraph 4.54 we have shown that the existence of a generation security standard affects the CEGB's costs because it requires the Board to hold plant in excess of the expected level of demand to meet certain contingencies. Other things being equal, changes in the standard affect costs in the short run via operating plant margins and the plant closure programme and in the long run via the influence of its planning margin on the requirement for new investment.

4.70. We observe that there is some difference of view on the appropriate basis for setting the generation security standard. We doubt whether it will ever be possible to derive estimates of marginal benefits sufficiently robust to form the basis for decisions. Fixing the generation standard is and will remain a matter of judgment. However, the quality of any judgment will be the better the more relevant information there is to hand on the effects of possible changes. Such information would certainly include estimates of effects of changes in the standard on the CEGB's costs in the short and long run via the relevant margins. On the 'benefit' side, we consider that estimates of how people would be affected in various ways, how many hospitals have emergency generators etc, are equally essential aids to judgment.

4.71. Because we are not convinced that sufficient information of this kind was brought to bear in the industry's own previous internal reviews of the security standard, we believe that the matter requires further study by the Electricity Council. We would also urge that any future review should involve full consultation with representatives of consumers.

4.72. We welcome the CEGB's statement in paragraph 4.61 that it intends to reconsider the planning margin before it again becomes relevant to plant orders. The margin, unlike the standard, requires re-examination every few years because both plant availability and forecasting success vary. The Board's observations in paragraph 4.61 that it expects to achieve better plant availability and that this should enable it to reduce the margin are also welcome. We consider that the planning margin is the responsibility of the CEGB, in consultation with the Council, because the judgments involved are on matters where the Board has the technical expertise and is best placed to gather the necessary information. However, we would regard it as in the public interest if the CEGB were to continue to make known its technical judgments to the Government and informed outside opinion so that they can be compared with events as they turn out.

CHAPTER 5

Investment decisions

Basic framework for investment planning and appraisal

5.1. The CEGB Planning Department works to an annual cycle, with investment planning culminating in a Development Review which presents the relative economics of alternative generating projects, in the context of the likely availability and price of fuels, and the plant/demand balance. (The plant/demand balance is the gross surplus or deficit of capacity the CEGB expects to have on the basis of the forecast of maximum demand it must meet.) A corresponding transmission plan is also produced. These documents provide the best estimates upon which the Board forms its judgments. The Electricity Council is then consulted and, subsequently, the proposals for the new generating plant programme are submitted to Ministers a few months later. These proposals are contained in the Plant and Load Review which also assesses the plant demand balance for the next nine winters. This document accompanies the Capital Investment Memorandum (CIM) which is drawn up by the Finance Department. The CIM contains the capital estimates of the proposed programme.

5.2. The Department of Energy discuss the proposals with the CEGB in some detail, and when satisfied, the Secretary of State for Energy approves the Board's capital investment budget and development proposals subject to any amendments or conditions he may wish to impose. It has been agreed by the industry and the Department that separate financial consent must be received from the Secretary of State before the CEGB may start the construction of any new power station. Similar constraints are not normally applied to new transmission projects but may be to exceptional ones such as the proposed new link with France.

5.3. In addition to the economic assessment contained in the Development Review considerations such as strategic requirements (for example, reducing the CEGB's dependence on any one fuel supply) and environmental impact are taken into account. The Planning Department makes its proposals, in consultation with all the CEGB's Regions and main Headquarters Departments and in particular with the two Construction Divisions (Generation Development and Construction Division—Barnwood—and Transmission and Technical Services Division—TTSD).

5.4. Investment appraisal concentrates upon determining what type of plant, if any, should next be acquired. When this is done, the most convenient site is chosen, which will often be that where preliminary planning is most advanced. The lead time in the CEGB's planning is governed primarily by the time taken to construct new main generating stations which, in normal circumstances, is assumed to be about six years from the placing of main orders to the commissioning of the first unit. Prior to placing orders the CEGB must submit its proposals to preliminary planning and consultative procedures; these may involve the holding of a public inquiry. These processes determine whether the CEGB receives consent to proceed under Section 2 of the Electric Lighting Act 1909. For nuclear stations, the Board must also obtain a Nuclear Site Licence. These preliminary procedures add several years to the lead time, and final plans for power station investment can therefore only be developed from projects whose preliminary planning is well advanced.

Annual planning timetable

5.5. The annual planning timetable is subject to minor variations from year to year, and is therefore best exemplified by giving the actual dates of key events for 1979–80:

A. Oct 1979	Estimates of future electricity demand for up to nine years ahead formally adopted by the Electricity Council.
B. Nov 1979	1979–80 Development Review, containing options and economic appraisals but not final investment proposals, presented by Planning Department to the Executive.
C. Dec 1979	1979–80 Development Review submitted to the Board, and to the Electricity Council.
D. Jan 1980	1980 Plant and Load Review (prepared by Planning Department) and draft Capital Investment Memorandum (prepared by Finance Department), containing budgetary provision for all capital investment requirements and specific proposals for new generating capacity, approved by the Executive.
E. Feb 1980	1980 Plant and Load Review and Capital Investment Memorandum submitted to the Board and subsequently withdrawn.
F. Feb 1980	Electricity Council adopted revised electricity demand estimates. (This revision of demand estimates was considered necessary in view of the sharply worsening economic prospects, and led to a further review of investment proposals).
G. March 1980	Revised Capital Investment Memorandum approved by the Executive.
H. April 1980	Revised 1980 Plant and Load Review and Capital Investment Memorandum approved by the Board, and submitted to the Electricity Council for its information.
I. April 1980	1980 Capital Investment Memorandum submitted to Government by the CEGB.
J. June 1980	1980 Transmission plan considered by the Executive.
K. July to Oct 1980	Planning Department consulted Regions, Divisions and other Headquarters Departments and prepared the Development Review 1980–81.

The appraisal of generation investment

TECHNIQUES OF APPRAISAL

5.6. The CEGB has developed a system planning model which simulates the operation of the CEGB's generation and transmission plant over the expected lifetime of any new generating plant which the CEGB might order against a given 'planning background'. The planning background consists of assumptions about the development of the demand for electricity and of generation capacity and represents a 'base' against which the effects of individual generation projects may be measured. The assumption on the development of generating capacity requires an initial view to be taken about the comparative economics of alternative generating plant options (which, in principle, is an output of the appraised process). This view, however, is influenced by the results of previous cycles of planning and appraisal activity. In present circumstances it also requires a judgment on the rate at which new nuclear plant can be introduced onto the system.

5.7. The planning background assumed in the 1979–80 Development Review was that there would be about 35 GW of nuclear generating capacity by the turn of the century, and that most large coal-fired units would be refurbished. Growth of electricity demand of about 1½ per cent per annum from 1980–81 to the end of the centruy and beyond was forecast consistent with the CEGB's estimates of the likely trend in electricity prices. Prices were assumed to be set at long run marginal cost and forecasts were derived using the CEGB's background estimates of fuel prices and basic estimates from the investment appraisal. Iteration was used to ensure the consistency of the investment appraisal and demand forecasts. The CEGB has told us that the planning background adopted for the 1980–81 Development Review[1] differs very greatly from that used in the 1979–80 review. The Board now assumes that there will be about 24 GW of nuclear capacity by the turn of the century and that demand will grow at only about 1 per cent per annum from 1980–81 onwards. Table 5.1 sets out in more detail the planning background assumptions on demand and nuclear generating capacity made in the 1979–80 and 1980–81 Development Reviews.

TABLE 5.1 **Planning background assumptions**

	1979–80 Review	*1980–81 Review*	*Difference*	
	GW	GW	GW	%
Restricted ACS demand estimates				
1990	53·2	49·8	−3·4	−6·4
1995	56·8	52·0	−4·8	−8·5
2000	60·5	53·7	−6·8	−11·2
2005	65·3	56·2	−9·1	−13·9
Total nuclear capacity				
1990	11	8	−3	−27·3
1995	21	13	−8	−38·1
2000	35	24	−11	−31.4
2005	46	36	−10	−21·7

Source: The CEGB

[1] The 1980–81 Development Review is dated November 1980. The Board did not make it available to us until 5 February 1981, which was too late to allow us to take its contents into account in our report. However, we were given on request certain information in advance about its contents and this is reflected at various points in the Chapter.

In explanation, the Board has told us that the changed assumption on the development of nuclear generating capacity is the result of lower demand forecasts together with the effects of more prudent assumptions on the starting date and subsequent expansion of the nuclear programme.

5.8. Given the planning background, the system model allows the effects of an investment project to be assessed in terms of the change in overall system costs which its operation in merit order effects. The cost streams associated with the project are discounted back to the present.

5.9. This exercise is undertaken using the technique laid down by successive White Papers on Nationalised Industries, which is to express all the inputs in constant prices (in real terms) and use a real discount rate. This avoids the need for a forecast of inflation in the economy as a whole, although forecasts of relative price changes are still required. The CEGB uses a 5 per cent discount rate, so that all new investment will achieve the 5 per cent Required Rate of Return set by Government in Cmnd 7131. An Allowance for general overheads is included in the cost stream so that the 5 per cent requirement for all new investment—including that part which does not offer a direct financial return—will be met if new projects pay their expected returns.

5.10. The individual cash flows which are relevant for a project appraisal are as follows:

(i) The capital cost and associated expenditure (eg insurance) set out as an annual stream.

(ii) The cost of decommissioning, dismantling and disposal of the station, net of scrap value. For a nuclear station such costs will arise for a number of years after it has ceased operating.

(iii) The fuel component of direct operating costs at the station. For a fossil-fired station, apart from the holding of some stocks, the expenditure on fuel occurs at about the time the fuel is used. The fuel cash flows for a nuclear station are much more complex; they cover the cost of the fabricated fuel elements, local storage of irradiated fuel, transport of irradiated fuel, reprocessing, intermediate long-term storage of waste, vitrification and ultimate waste disposal.

(iv) Direct operating costs other than fuel, covering wages and salaries, repair and maintenance, materials, rents, rates, insurance etc. An allowance is included for the total administrative costs which the CEGB incurs.

(v) The cost effect of operating the new station on other stations. This arises because the new plant operates in merit order, and hence saves operating costs at other stations. The difference between this operating saving and the costs of operating the new station is the net system saving, and counts as a credit against the cost of carrying out the project.

The model takes account of all these elements.

5.11. The appraisal therefore shows the effects on the system of acquiring or retaining capacity when an assumed demand must be met, and identifies the method with the lowest net present cost. The costs are independent of the revenue-earning capability of the CEGB, which depends upon the movements of demand and prices. In this appraisal the benefits are net system savings and the costs are items (i) to (iv) above; a project is worth undertaking because of the savings in operating costs it offers if the present value of benefits is greater than the present value of the costs.

5.12. Different projects do not always offer the same capacity, nor do they necessarily have the same expected lives. To adjust for the first consideration the net present cost of each project is divided by its capacity, and is expressed per kilowatt. The second consideration is dealt with by annuitising the net present cost for each station over its expected lifetime. The resulting adjusted measure of the economic value of each investment is then an annuitised net present cost, in units of £/kW per annum. The CEGB's Planning Department calls it Net Effective Cost or NEC. The most attractive project on economic grounds is the one with the lowest NEC.

5.13. The 1979–80 Development Review presents estimated NECs for six types of high merit order plant: an 1100 MW PWR with a comparably sized turbo-generator, 1100 MW PWR with two turbo-generators each of half its output, a 1,320 MW AGR with two turbo-generators of 660 MW a 3 × 625 MW coal station, a 1 × 625 MW coal station, and a 2 × 330 MW coal station. The last is included because it is thought to offer a different balance between capital and operating costs, by virtue of better availability. It also shows estimated NECs for three types of gas turbine plant, which are designed to meet peaking demands and to provide system reserve (a 2 × 70 MW gas turbine station, a 4 × 70 MW gas turbine station, and a 35 MW auxiliary gas turbine). All these options merited consideration because the preliminary planning was well advanced, or at least there was a prospect of finding or selecting sites to go ahead in the fairly near future.

5.14. Table 5.2 is taken from the CEGB's 1979–80 Annual Report and shows how the NEC is built up for different types of plant. It uses the CEGB's basic estimates (see paragraph 5.95).

TABLE 5.2 **Basic estimates of Net Effective Cost of future stations (March 1980 price levels)**

		Nuclear £/kW pa	*Coal-fired* £/kW pa
A.	Capital charges at station and provision for decommissioning interest during construction	77	36
B.	Inclusive fuel costs	34	113
C.	Other costs of operation	12	10
	Generating costs	123	159
D.	*Less* fuel saving from displacing less efficient plant	148	143
	NEC*	−25	+16

Source: The CEGB

* Excluding transmission which in each case amounts to £5/kW pa for capital charges and interest during construction together.

5.15. When a project has a negative NEC, it is worth undertaking for the saving in fuel and operating costs, which outweighs all construction and other operating costs. However, a project with a positive NEC may still be cost saving, because the project may be less costly than the alternative of retaining existing plant in service. Neither the retention of existing plant until it is life expired nor the deferring of the closure of plant which has reached its 'book' life involves investment. The relevant figure for comparison with investments is the avoidable cost of keeping a plant available to the system (ie able to go on load at short notice). This includes wages, salaries, rents, rates, insurance, repairs and maintenance and the allowance for general overheads. However, the plants near the end of their lives are not necessarily at the bottom of the merit order, although they are very low. The 'Net Avoidable Cost' of old plant of this kind therefore includes whatever system credit the model predicts that they will offer if retained. This Net Avoidable Cost of deferring retirement is the yardstick against which potentially cost-saving investment is measured, and is likewise expressed in units of £/kW per annum.

5.16. In its 1979–80 Development Review the CEGB estimated that it could meet demand in the planning year (1986–87) without any investment in new generating plant, and it was therefore concerned to identify whether investment would be cost-saving. However, in any future scenario in which demand increases so much that part of the increase cannot be met by deferring retirements, new investment would be necessary, and hence the appraisal would need to discover the cheapest way to meet the increase. This would be the investment project with the lowest NEC, whatever the Net Avoidable Cost of plant retirement.

OPTIONAL INVESTMENT

5.17. The Board has told us that it distinguishes between 'necessary' investment 'required to meet a minimum view of . . . [the Board's] . . . statutory requirements whether under . . . [the Electricity] Acts or others' (for example, health and safety legislation) and 'optional' investment. Investment in generation and transmission capacity required to meet the relevant security standards falls into the first category. Examples of optional investment include schemes to improve the thermal efficiency of generating plant, national spares (see paragraph 9.26) and cost-saving transmission projects. 'Necessary' projects are appraised using a 5 per cent discount rate (see paragraph 5.9) and are not subject to a pay-back period. Currently, optional projects must earn a 15 per cent real rate of return and pay back within three years.

5.18. The existence of a category of optional investment acts as a capital rationing device in circumstances in which the investable funds available to the Board are insufficient to finance all of the projects identified within the organisation capable of earning a 5 per cent real rate of return (see paragraph 5.9 above). The Board has told us that the application of the optional investment rules bears most heavily on projects originating in the Board's operating regions and that, so far, it has not resulted in the rejection of any proposals for acquisition of national spares. One example offered by the Board of an optional project which has been rejected (because it failed to meet the three year pay-back condition) is a joint venture between the Board and the University of Manchester Institute of Science and Technology for a combined heat and power project costing £2 million.

Forecasting key variables

5.19. Having described the framework used by the CEGB for appraising alternative generating plant options, we now examine the procedures used for forecasting the future values of the key variables identified in paragraph 4.6. Our approach is to describe the way the Board forecasts each of the variables and the analysis and judgment which underlie the forecasts. We then illustrate the sensitivity of the 'basic' NECs of alternative types of generation project to individual variations in the forecasts. We also illustrate the sensitivity of 'basic' NECs to variations in the planning background.

(1) **Fuel prices and availability**

5.20. As the CEGB's evidence to the Select Committee on Energy (referred to in paragraphs 5.110–5.111) emphasises, judgments on the future course of fuel prices and availability are a key element in the CEGB's current choice of generating plant investment programme. Because of the importance of fuel prices both in the context of long-term investment appraisal and in short-term operational planning, forecasts are prepared jointly by the Planning, Finance and Operations Departments of the Board. Whilst the forecasting of future fuel prices and availability is a critically important input to the CEGB's investment appraisal, it is also a highly demanding exercise, involving an assessment of the operation of a number of markets and in some cases their interaction over a very long period into the future. Moreover, there are important differences in the structures of the markets concerned, with the CEGB's role varying from passive price taker to dominant purchaser in the context of bilateral monopoly.

5.21. The CEGB prepares forecasts of domestic and internationally traded coal prices, heavy fuel oil and gas oil prices and the costs of the nuclear fuel cycle. The forecasts of world oil prices and availability are the outcome of internal analysis by the CEGB, but heavy reliance is placed on the views of informed outside opinion. We have concentrated our attention on the CEGB's approach to forecasting coal prices and availability and nuclear fuel cycle costs.

COAL PRICES AND AVAILABILITY

5.22. Because of the current and prospective importance of NCB coal as a fuel source the Board has devoted considerable effort to the forecasting and analysis of the costs, prices and availability of NCB coal. Detailed forecasts of these variables are produced for the planning period seven years ahead, and less detailed forecasts are prepared to the end of the century. In principle, appraisal of generating plant choice must take account of price movements for perhaps 30 years or more in the future, but the assumptions on changes beyond the turn of the century are essentially extrapolations rather then systematic forecasts.

5.23. The CEGB adopts a two-stage approach to forecasting future movements in the NCB's prices. At the first stage, an analysis is made of factors underlying NCB costs of production. These are divided into three elements:

(i) Wage and wage related costs which are calculated by balancing the effects of productivity increases and labour cost increases. The rate of productivity increase is in turn linked to the volume of investment in new and existing capacity and hence to charges.

(ii) Other operating costs.

(iii) Capital charges. This item depends, *inter alia,* on the extent to which interest on work in progress may be deferred by capitalisation.

The CEGB's latest central assumptions on the movement of the NCB's costs up to 1987–88 are set out in Table 5.3 below:

TABLE 5.3 **The NCB's costs of production and prices* (p/GJ)**

(March 1980 price levels, 24 GJ/tonne)

Deep-mined	*1979–80*	*1987–88*	*% change per annum*
Wage and wage related costs	80	86	1
Other operating costs	48	58	2½
Capital charges	13	20	5
Total deep-mined costs	141	164	2
Opencast	85	119	4
OVERALL COSTS	135	158	2·0

Source: The CEGB

* Assuming miners' wages rise to 30 per cent above median wages, from the present 12 per cent to 15 per cent.

5.24. The CEGB then proceeds to make estimates of 'pit-head' prices by applying assumptions on the future scale of grants, the NCB's operating surplus or deficit, and the coal industry pricing structures. The CEGB currently assumes that by the late 1980s Government grants to the industry will have been stopped, that the NCB will achieve a measure of profitability, and that the current discount for coal purchased by the CEGB in the Industrial Coal Pricing Structure will disappear. The effects of these three assumptions in translating movements in underlying costs into pithead prices to the CEGB are shown in Table 5.4 below. The outcome is that the pithead price to the CEGB is expected to increase at about twice the rate in real terms of the NCB's underlying production costs. The 1979–80 Development Review did not discuss the inter-relationships between this assumption and the Board's commercial stance of seeking to limit the NCB's prices to the rate of inflation in the years immediately ahead.

TABLE 5.4 **Derivation of the NCB's prices from its overall costs (p/GJ)**

	1979–80	*1987–88*	*% change per annum*
The NCB's overall costs	135	158	2·0
Grants	(–)3	0	—
The NCB's operating deficit/-surplus	(–)8	5	—
'Preference' to electricity coals	(–)7	0	—
CEGB price (pithead)	117	163	4·2

Source: The CEGB

5.25. In 1979–80, the costs of coal handling and transport added a further 7½ per cent to the pithead price. Given a set of colliery—or coalfield—specific pithead prices and assumptions about the unit cost of handling and transportation, forecasts of the delivered price of coal are derived from the overall system model which simulates the flows of coal from point of production to point of use. Up to the late 1980s it is assumed that the overall costs of handling and transportation per unit of NCB coal consumed will increase at about the same rate as NCB pithead prices. Hence the increase in NCB delivered prices is forecast to be the same as the increase in pithead prices (4·2 per cent per annum between 1979–80 and 1987–88 in the central case, within a two standard deviation range of 2·5–5·7 per cent).

5.26. These latest (1980) central estimates for coal prices represent a downward revision (of about 8½ per cent) in the expected price for 1986–87 by comparison with the estimates prepared in 1979. The main reason for the downward revision is that the CEGB now believes the capital cost component of the NCB's costs will be somewhat less than was assumed in the 1979 forecasts, due in part to the application of the provisions for the deferral of interest charges in the Coal Industry Act, 1980.

5.27. Over the long term, the CEGB expects the rate of increase of the NCB's costs to decline somewhat as a result of investment in lower cost mines. The Board has also told us that its view of the NCB's costs in the longer term assumes that, once achieved, miners will maintain but not increase the 30 per cent or so real wage advantage over the median for all workers. The 1979–80 Development Review therefore suggests that beyond the mid-late 1980s, the NCB's costs will increase by only about 1 per cent per annum in real terms. In line with its recent downward revision of forecast the NCB prices in the medium term, the Board also expects the price of NCB coal around the turn of the century to be somewhat less than expected at the time of the 1979–80 Development Review. Its central estimate of NCB pithead prices in the year 2000–01 is now 200 p/GJ compared to a figure of 224 p/GJ in the 1979–80 Development Review (both figures at March 1980 prices).

5.28. The Board also assumes a widening gap between production costs of coal and the world market price of oil which will allow scope for both increased profits (to finance higher investment) and for some increased penetration by coal of markets currently held by oil. The Board's current central assumption is therefore a rate of price increase charged by the NCB of 1½–2 times the rate of underlying cost increase between the late 1980s and the turn of the century.

5.29. Closely linked to the CEGB's forecasts of the NCB's prices are its prediction of NCB output and the availability of NCB coal supplies to the CEGB. The CEGB currently assumes that the total production of the NCB will decline from the present level of about 120 million tonnes to about 114 million tonnes in 1986–87 and only about 110 million tonnes per annum by the end of the century. The CEGB has explained to us that it believes the main constraint on the growth of the NCB's output will be an organisational one. It points out that the Selby project is the first major 'green field' investment in deep-mined coal capacity for many years, and that to make good or exceed the current depletion rate of existing capacity may require a major increase in the NCB's internal project management resources which the CEGB thinks could take time to provide.

5.30. The CEGB also assumes that in the long term the availability of coal for electricity production in the United Kingdom will decline more rapidly than the NCB's total output. The assumption underlying its estimates of availability is that the supply of coal for electricity will be a residual after other potential demands for steam coal have been met. Because other industrial demands for steam coal are forecast to increase, the residue available to the CEGB is expected to fall between the late 1980s and 2000, with an especially sharp drop in the second half of the 1990s. Specifically, the CEGB assumes that by comparison with its current (1979–80) purchases from the NCB of about 78 million tonnes of coal a year, only about 70 million tonnes (within a two-standard deviation range of 60–80 million tonnes) will be available in 1986–87; 70 million tonnes (within a two-standard deviation range of 65–75 million tonnes) in 1992–93 and only 55 million tonnes by 2000 (within a two-standard deviation range of 40–70 million tonnes). The Board has told us that on the basis of the planning background assumed in the 1980–81 Development Review it currently forecasts its coal burn around the end of the century at about 63 million tonnes a year. If only 55 million tonnes could be purchased from the NCB, then the balance (of about 8 million tonnes) would have to be supplied by coal imports.

5.31. Both new nuclear and new coal-fired generating capacity produce net system savings in fuel costs (the difference between items B and D in Table 5.2). Other things being equal, a change in the assumed availability of NCB coal would affect the estimated size of the system saving (and hence the project NEC) only if it led to a change in the price of the fuel which would be saved if the investment were made. This would require, first, the existence of a difference between the price to the CEGB of imported and NCB coal at the margin, and secondly, that the change in availability was sufficient to alter the sourcing of some of the coal which would not be purchased if the investment went ahead.

5.32. The CEGB's latest review of fuel price prospects states:

> 'if world economic growth is to continue at the rates predicted through the 1980s, coal's contribution to world energy must substantially increase'.

The Board has told us it expects the total volume of world trade in coal to double (from 200 to 400 million tonnes per annum) and the volume of trade in steam coal to increase by a factor of 3 or 4 (from 50-60 million tonnes per annum). It hopes to obtain up to 10 million tonnes per annum of imported coal if necessary over the period 1980–81 to 1987–88 and beyond, provided purchasing arrangements are made sufficiently early.

5.33. The 1979–80 Development Review identifies Australia, South Africa, the USA and possibly Poland as countries of most interest to the CEGB as long-term sources of steam coal supply. In the long term, however, it is expected that India, Venezuela, Colombia, Indonesia and Swaziland may also offer some potential as they all have promising reserves awaiting exploitation. The Review also points out that producers are likely to prefer long-term contracts and possibly capital contributions before developing further mining capacity and that this will limit the scope for ad hoc spot purchases.

5.34. On prospects for world market prices in the long term, the CEGB's latest view is:

> 'In the medium and longer term world coal prices will be largely related to marginal production cost, but the excess production volume in the USA is still tending to have a dampening effect on price at present. Prices are not directly linked to world oil prices. However spot and short-term tonnage prices have recently increased sharply as a result of the short-term coal shortage, itself a function of port congestion and firm demand caused by high world oil prices. The fragmented nature of the market and the contractual traditions of the trade will tend to work against the establishment of a direct link between oil and coal prices; similarly it is not expected that producer cartelisation will evolve in the period.
>
> World prices are expected to increase as the costs of extraction and shipment increase, the marginal development costs of Australian and the larger US producers determining the minimum prices for new contracts over the period. Existing producers are expected to attempt to achieve these price levels at contract renewal dates.
>
> Our forecasts of world coal prices are made on the assumption that the increase in prices will be sufficient to attract new investment in production and infrastructure, whilst retaining a sufficient differential over oil prices to encourage consumer investment in power stations and reception facilities. The actual movement of price over the period will probably exhibit cyclic tendencies because of the inevitable supply/demand mismatches which will occur.'

5.35. Another major potential influence on the forecast price of imported coal and oil is the assumption on the future level of the sterling exchange rate. For the 1979–80 Development Review, the Board assumed a dollar-sterling exchange rate of $2·00 = £1·00 for the period from 1985 to 2000. It currently assumes a further decline (to $1·50 = £1·00 in the year 2000) but has told us that this estimate is not in fact critical to current decisions. It has also said that further work on the future path of the sterling/dollar exchange rate is in hand.

5.36. The change in the central case assumption about the long-term sterling exchange rate is one factor which currently causes the CEGB to take a markedly more pessimistic view on the long-term development of imported coal prices than was evident in the 1979–80 Development Review. The Review stated that (in March 1979 prices) 'it is assumed that coal imports into the UK [in 2000-01] will be available at 5 per cent below the NCB pithead price, ie 178p/GJ (within a two-standard deviation range of 128–228 p/GJ) cost including freight at a deep water port'. This price would represent a real rate of increase of about 2·7 per cent per annum from the 1979–80 figure. By contrast the CEGB now believes that a very substantial price differential in favour of NCB coal will have opened up by the turn of the century. It assumes as a central case for investment appraisal purposes that, whilst in March 1980 prices, the average delivered price of NCB coal will be 216 p/GJ, the price of imported coal in the year 2000–01 will be 300 p/GJ delivered.

5.37. We have seen that the Board currently expects the significant differential in the price per GJ between imported coal and oil to persist in the long run. This represents a major revision of the Board's earlier views on this relationship as presented in previous Development Reviews. Even as late as the 1976 Review, the Board expected that in the long run the price of imported coal would keep closely in line with that of oil. On the basis of this forecast, and on the assumption that the introduction of any new coal-fired stations would lead to an increased level of coal imports, the Development Reviews in 1974, 1975 and 1976 showed the estimated basic NECs of oil-fired stations to be less than those of new coal-fired plant. The sensitivity analyses displayed in these Reviews made no provision for a change in the relative prices of marginal coal and oil and so the robustness of the supposed advantage of oil-fired stations was not explored.

5.38. The Board's views on the future output of the NCB and availability of NCB coal are somewhat more pessimistic than those expressed by the Department of Energy, whom we consulted. The Department's last published projections give a range of United Kingdom coal output around the turn of the century of 137–155 million tonnes per annum. Since the projections were published in 1979, short-term prospects for economic growth have worsened. This is likely to have at least some effect on the development of demand for coal and the level of supply required. The Department have also told us that, on current prospects, they do not expect the availability of coal to the CEGB from the NCB to be significantly less than the present volume up to the turn of the century.

5.39. On the prospects for world coal trade, we have compared the CEGB's views with those of the recently published World Coal Study (WOCOL). Of 80 contributors and associates to the WOCOL study, 35 are identifiable as having direct coal interests. Nevertheless, we think the analysis of world trade developed in the report affords a useful perspective on the Board's own view.

5.40. On the supply side, WOCOL aggregates current export expectations about tradable coal in the year 2000. This gives a range of 550–700 million tonnes which compares with the CEGB's expectations of 400 million tonnes per annum. On the demand side, the study estimates 'needs' for steam coal in the range 300–680 million tonnes in the same year. This is predominantly for electricity generation, and is calculated against a background of steady nuclear expansion. WOCOL argues that the driving force in developing world coal trade must be decisions on the part of utilities (such as the CEGB) to invest in import-using coal-fired generation plant. Given the limited present (and likely future) role of spot markets for coal, the need is for utilities to sign long-term contracts for coal deliveries. Without such commitments, WOCOL predicts that the world coal market will remain predominantly specialised in coking coal.

NUCLEAR FUEL CYCLE COSTS

5.41. The CEGB's arrangements for procuring nuclear fuel cycle services are discussed in detail in Chapter 7. Here we concentrate on the forecasting of nuclear fuel cycle costs as part of the generating plant investment appraisal.

5.42. The four main elements in the nuclear fuel cycle which we identify in Chapter 7 are:

(i) procurement of natural uranium;

(ii) enrichment of the fissionable isotopes;

(iii) fabrication of fuel elements;

(iv) management of irradiated fuel.

The CEGB has told us that, very roughly, each item accounts for about a quarter of the estimated present value of nuclear fuel cycle costs used in deriving basic NECs of nuclear plant. It has also told us that the cost estimates used in calculating basic NECs are based upon a purchasing programme consistent with the commissioning of about 1½ GW per annum of new nuclear capacity from 1986–87 onwards.

(i) *Uranium*

5.43. The CEGB has so far been successful in obtaining supplies of natural uranium through long-term contracts with specific suppliers at prices significantly less than the estimated spot market price. Future contracts, however, may be based on a notional world market price which will reflect demand conditions as well as local costs of production. In forecasting future uranium prices, the CEGB must therefore take a view on the development of demand and supply conditions. It has told us that, so far, it has not developed any formal models for predicting future prices but, conceptually at least, it estimates the rate of commissioning of nuclear plant and of likely new mining capacity worldwide; hence it identifies a future supply/demand balance and can estimate the possible effect on prices. As with imported coal, a major influence on the future supply price to the CEGB is the sterling-dollar exchange rate. As we have seen, the CEGB currently expects this to decline by about a third by the turn of the century. In the light of these factors, it currently expects contract prices 'to double or more' in sterling terms at 1980 prices between now and the turn of the century. The CEGB has told us that it does not expect the future contract prices to vary significantly with the total level of its purchases.

(ii) *Enrichment*

5.44. The CEGB contracts with URENCO for the enrichment of fissile material at a basic price which is subject to cost escalation clauses and which may be subject to adjustment in the light of the relationship between URENCO costs and the charges of other suppliers of enrichment services. The CEGB has told us that, in its view, the risks of unanticipated real cost escalation arising from technical uncertainty are relatively small because the centrifugal process is now technically well-established and does not involve any significant health or safety hazards.

5.45. The CEGB expects the cost of enrichment of fissionable material to rise in real terms between now and the turn of the century by about 40 per cent. In its view, the most important underlying influence on future price levels will be the cost of electricity supplied for the gaseous diffusion process used by US suppliers of enrichment services.

5.46. *The market structure for fabrication and reprocessing.* For nuclear fuel fabrication and reprocessing the CEGB currently contracts either exclusively or for a very large proportion of its purchases with British Nuclear Fuels Ltd, whose plant capacity decisions are heavily influenced by expectations about prospective levels of the CEGB's purchases. In the past, this form of trading relationship with BNFL has encouraged the inclusion in contracts of price variation clauses which introduce a penalty element in the event of purchases falling short of the level on which capacity decisions had been based. The CEGB has explained to us that in the future it hopes to develop a somewhat looser trading relationship with BNFL. This would be based on the recognition that, compared with the position over Magnox fuel, BNFL's capacity would be less specific to the CEGB's requirements, that there would be a wide range of potential suppliers of fabrication and reprocessing services (for PWR fuel in particular), and finally that, if necessary, reprocessing could be deferred for many years by long-term storage.

(iii) *Fabrication*

5.47. The fabrication of AGR and PWR fuel elements is considered now to be a normal manufacturing process based on a well-established and stable technology. Given the build-up of nuclear capacity assumed in the planning background used in the 1980–81 Development Review, the CEGB has told us that it expects the cost of fabrication to fall by about 30 per cent in real terms between now and the turn of the century. This reflects the expected beneficial effects of a steadily increasing rate of plant throughput on unit costs.

(iv) *Reprocessing*

5.48. The nuclear fuel cycle cost estimates used in investment appraisal assume that irradiated fuel will be reprocessed. As explained in Chapter 7, neither the reprocessing and waste disposal, nor the long-term storage options for the management of irradiated AGR and PWR fuel have yet been costed in detail. The cost estimates for reprocessing are judgments by the CEGB based on an updating for inflation of outline costs made by BNFL for the Windscale Inquiry into the thermal oxide reprocessing plant (THORP) in 1977.

5.49. Experience with Magnox fuel reprocessing has shown a tendency for cost estimates to rise for the following reasons:

(i) engineering difficulties resulting in a shortfall in planned throughput;

(ii) pressure to reduce the radiation dose received by operators;

(iii) the need to reduce the amount of radioactivity in effluent.

BNFL does not expect the same degree of cost escalation to occur in the future because its plant designs recognise the Magnox experience and already provide for much lower operational dose rates.

5.50. The 1979–80 Development Review shows equilibrium nuclear fuel cycle costs for AGR plant, at March 1979 prices, increasing from 0·37 p/kWh in 1986–87 to 0·47 p/kWh at the turn of the century. This represents a 1·7 per cent per annum increase. It went on to say that:

> 'There are, of course, major uncertainties in any forward projection of prices over such a long period. As an example, the combined effect of adverse market forces operating on uranium ore and enrichment prices, a 100 per cent increase in reprocessing capacity charges, and a 20 per cent increase in fabrication and reprocessing costs would cause fuel cycle costs to rise some 50 per cent higher than presently estimated for 1990–91 and 2000–01.'

In further explanation the CEGB has told us that the 50 per cent figure for fuel cycle cost increase is based upon the effect of uranium ore prices increasing by 50 per cent and enrichment prices by 20 per cent over 'best estimate' values. The CEGB has also told us that the nuclear fuel cycle cost estimates for 1990–91 and 2000–01 used in the 1980–81 Development Review are 15 per cent higher in real terms than the figures used in the 1979–80 Review.

SENSITIVITY OF BASIC NECs TO VARIATIONS IN FUEL PRICES

5.51. The CEGB has supplied us with estimates of the effect on the NECs of nuclear (AGR) and coal-fired plants if different marginal coal prices and nuclear fuel cycle costs from those used in estimating basic NECs are assumed. The CEGB has told us that in the 1980–81 Development Review, basic NECs are estimated on the assumption that marginal coal is available to it at a price corresponding to the Board's current central estimates of the NCB's delivered price, which currently stands at 216 p/GJ for the year 2000–01. Table 5.5 below illustrates the effects of variation both upwards and downwards in this assumption. Cases A and B assume that the marginal coal is imported. Cases C and D assume that the marginal fuel is available at a price corresponding to an NCB pithead price of 190 p/GJ and 170 p/GJ respectively.

TABLE 5.5 **Sensitivity analyses of basic NECs to variation in fuel costs (£/kW/per annum, March 1980 prices)**

	Nuclear (AGR)		*Coal-fired*	
Basic NECs	−18		+22	
Sensitivity analyses	*Change in NEC due to specified factor*	*Modified NEC*	*Change in NEC due to specified factor*	*Modified NEC*
	(1)	(2)	(3)	(4)
(1) Variations from the forecast marginal coal price				
(A) plus 40%	−26	−44	−2	+20
(B) plus 15%	−15	−33	−1	+21
(C) minus 5%	+7	−11	+1	+23
(D) minus 15%	+21	+3	+3	+25
(2) Variations from the forecast nuclear fuel cycle costs				
plus 5%	+2	−16	—	—
plus 20%	+8	−10	—	—

Source: The CEGB.

5.52. Columns (1) and (3) show the change in NEC produced by the outcome in question for nuclear (AGR) and coal-fired plant respectively. Columns (2) and (4) show the modified NECs associated with the identified outcomes.

5.53. If coal prices turn out to be higher than the central case assumption then the present value of the system savings, produced by displacing existing coal burning capacity by nuclear or more thermally efficient coal-fired plant, will increase. The converse holds if coal prices are less than those assumed in making the basic NEC estimates. Variations in nuclear fuel cycle costs affect only nuclear NECs.

5.54. It emerges from Table 5.5 that the estimated NEC of nuclear plant is highly sensitive to variations in the assumed rate of increase of marginal coal prices. The NEC of coal-fired plant by contrast is relatively insensitive to variations in coal prices. This difference may be explained by reference to the components of the basic NECs shown in Table 5.2. For nuclear plant, variations in coal costs affect only one component of the relatively large difference between items (B) and (D). By contrast, for coal-fired plant an equivalent variation affects both items in the same direction, so that the effect of the difference between the two is muted.

(2) **Construction costs and time**

5.55. The estimation of project construction costs and times is an important part of the appraisal process. Construction costs directly affect the NECs of generating projects (the sensitivity depending on the degree of capital intensity which varies between different types of project, nuclear plant being very much more capital intensive than conventional). Delays also raise costs (particularly interest during construction) and defer benefits. Forecasts of completion times are also an important element in forecasting the plant/demand balance, and hence affect decisions on plant closures.

5.56. Forecasts of construction times and costs used in investment appraisal are prepared by the CEGB's two Construction Divisions—Generation Development and Construction Division (Barnwood) and Transmission and Technical Services Division. Because our main concern has been the appraisal of generating plant investment, we have concentrated attention on the methodology that Barnwood employs in estimating construction costs and time for project appraisal purposes.

5.57. Estimation of construction costs and times presents a particular problem for the CEGB in current circumstances. Major plant orders have been infrequent (Drax completion and Heysham II were the first orders of coal and nuclear plant respectively for over ten years) and, like many other enterprises undertaking large construction projects in the United Kingdom, the CEGB has experienced consistently large cost and completion time overruns. The long gap between orders creates problems because cost estimation involves updating the best information from the past, in the absence of any better information. At the same time the CEGB has identified some of the causes of poor construction performance and has taken action to deal with them. It claims that because of these actions recent historical experience is not a good guide to the most likely outcome in the future.

CONSTRUCTION COSTS

5.58. Barnwood's estimate of construction costs prior to the receipt of tender information is derived by adding a start-to-finish allowance (currently 17½ per cent) to a basic cost estimate. This is not to be confused with the risk margin discussed in Chapter 3. The basic cost estimate is essentially an extrapolation of the price at which suppliers contracted to construct an equivalent design of plant in the past. In principle this extrapolation must take account of:

(*a*) changes in relative wages and relative prices which affect the real cost of projects;

(*b*) changes in the number of man-hours needed to carry out a given design;

(*c*) changes in design—whether for safety, quality or technical improvement;

(*d*) changes in the commercial climate—contractors' level of business and market power.

5.59. In the past Barnwood's work on cost estimation has concentrated mainly on items (*a*), (*b*) and (*c*) above. This has been done by trying to take explicit account of the effect of known design changes on the construction man-hours, and by the use of price indices built up from disaggregated data on the known movements in the costs of labour, power equipment items and materials applied to whatever contract price information is available. When there are long intervals between orders, however, significant changes may occur in the competitive climate and the level of suppliers' business between successive plant orders. The price indices, being based on adjustments to contract prices negotiated under different market conditions, may then fail to reflect these underlying changes.

5.60. There is evidence from the two most recent major power station projects considered by the Board (Heysham II and Drax completion) that failure adequately to take account of changes in market conditions has contributed to a significant under-estimation of costs in investment appraisal documents. Thus, the estimated real cost of the Heysham II project as presented in the 1980 CIM was 25 per cent higher than the estimated cost shown in the 1979 CIM. The CEGB has told us that, in large part, this was because the 1979 figure had been based on an extrapolation of cost estimates (made in the Thermal Reactor Assessment prepared in 1977 by NPC) which had implicitly assumed a higher level of plant ordering and a more competitive commercial environment than actually prevailed when tenders for plant were invited. Similarly, the estimated cost of Drax completion shown in the 1977 Development Review was 9 per cent less in real terms than the scheme estimate (based on contract price data) shown in the 1979 CIM. The CEGB has told us that in this case the under-estimation of costs arose mainly because they had not taken adequate account of the consequences of single (as opposed to competitive) tender action.

5.61. The start-to-finish allowance is intended to take account first of the possibility that the CEGB's judgments about the effects of factors (*a*) to (*d*) above will turn out to be different from those of potential suppliers (commercial risk), and secondly, of the risks arising from delays, design changes and industrial relations problems, all of which tend to increase costs. In principle, the start-to-finish allowance should also be based on a judgment of the impact of any relative price effects during the lengthy construction period. These may, of course, be either positive or negative. The CEGB has stressed that the scheme estimate derived by adding together the basic cost estimate and the start-to-finish allowance is an estimate of what the project would cost if started as soon as possible. If the start is delayed then it would be necessary to update the estimate. It is not correct to assume, therefore, that the estimation procedure itself is necessarily at fault if the estimated cost increases in real terms between successive development reviews (as happened with the estimates for Drax completion in the early and mid 1970s).

5.62. Barnwood determines the size of the start-to-finish allowance by first examining cost overruns on past projects and then adjusting the average value derived from this analysis to take account of changes in the industrial relations climate, in project management methods and contractual relationships with suppliers. Barnwood has told us that for the CEGB's initial group of large (500 and 660 MW) fossil-fired stations it estimates the real cost increase over the original base date estimate to have been 23 per cent. On the four AGR stations the increase has ranged from about 36 per cent for Hinkley Point 'B', to a current estimate of about 145 per cent for Dungeness 'B', with an average of about 95 per cent. The expected increase for the three oil-fired stations currently under construction is 32 per cent.

5.63. The Board has told us that its estimates of past cost overruns are based on authorised volume of work changes at scheme base date prices. It has been unable to give us any estimate of the real cost variation arising from the application of contract price adjustment procedures, ie the size of any differential between the inflation of power station costs and costs in the economy as a whole. In order to assess the effects of this omission in the past we have compared (in Figure 5.1) a Barnwood index of the costs of coal-fired power station construction with the implied index of total home costs[1] for the period 1965–79. On this basis the real cost of the components of coal-fired power station construction increased by about 21 per cent, or by about 1·4 per cent per annum compound, between 1965 and 1979.

5.64. This result indicates that the estimates of real cost increases provided by the Board are very likely to represent under-estimates of the true real cost increase in its power station construction programme in the past 15 years or so.

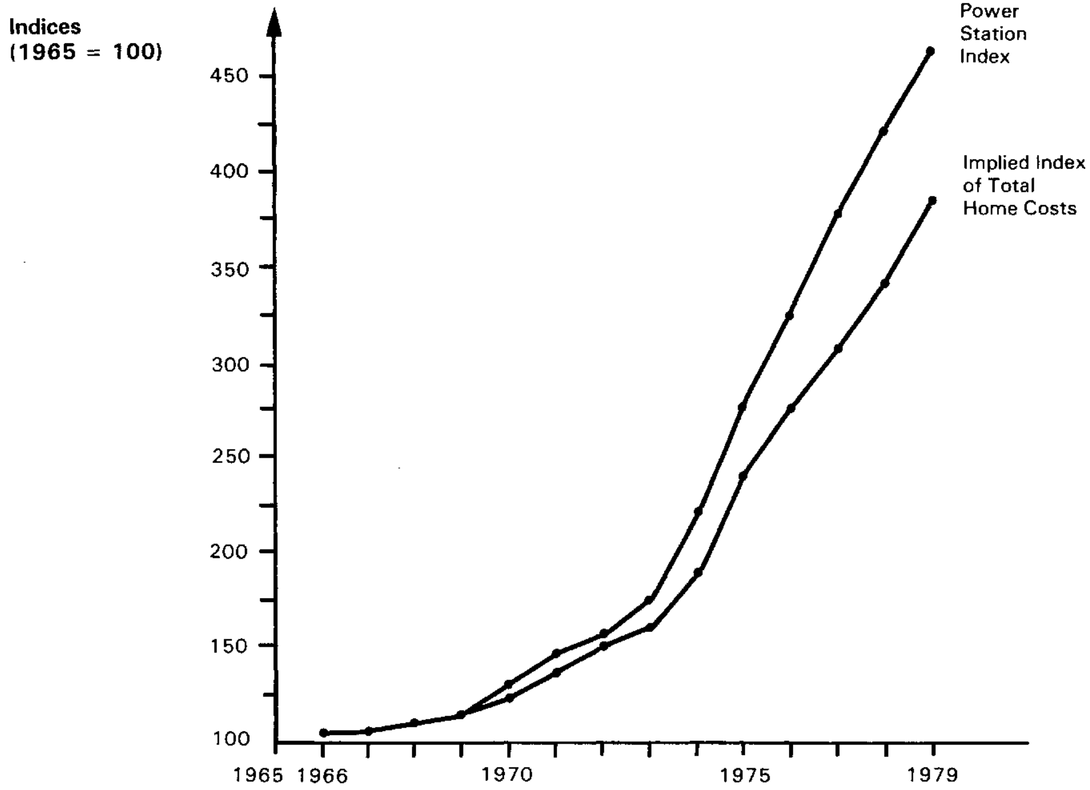
5.65. Despite the wide variations in cost overruns experienced on projects in the past, Barnwood has told us that a start-to-finish allowance of 17½ per cent is judged appropriate for all types of power station project. This figure

[1] *Source: Economic Trends.*

FIGURE 5.1

CEGB Index of Power Station Construction Costs and Implied Index of Total Home Costs

Source: Economic Trends



is about three-quarters of the average cost overrun experienced on coal-fired stations, about half of the figure experienced in oil-fired stations, and less than a fifth of the average overruns on AGR stations. In each case any relative price effects arising from contract price adjustment during construction have been excluded.

5.66. In explanation, Barnwood has emphasised the prototype nature of the first generation of AGR plant. It has also told us of the actions it has taken to improve past performance on construction cost (and time) overruns. These include:

(1) a high degree of design replication;

(2) the introduction of design contracts in situations where design replication is not feasible. In contrast to the first series of AGR stations, the present AGR and the first PWR stations are the subject of design contracts which will allow the negotiation and planning of main contracts and construction;

(3) the maximum use of lump sum price contracts;

(4) the introduction of contractually based federal arrangements between contractors on site (the Management Group) which the CEGB hopes will significantly improve industrial relations and site labour productivity;

(5) the introduction of the key date procedure;

(6) development of the relationship with NII in respect of nuclear stations.

5.67. Finally, Barnwood has said that notwithstanding the management action identified above the figure of 17½ per cent represents a conscious under-estimate of the likely effects of the factors identified in paragraph 5.58. Barnwood says that it prefers to under-estimate this element because publication of a central estimate could have a self-fulfilling effect. It follows that the construction cost figures used by the CEGB's Planning Department to estimate basic NECs were and are under-estimates and not central estimates.

CONSTRUCTION TIME

5.68. The Board has told us that the basic estimates of project construction time which are used by the Planning Department to compute basic NECs are derived from the output of a critical path analysis carried out by Barnwood prior to the letting of contracts. This critical path analysis is based on past experience and engineering judgment, and will be more robust the more experienced the CEGB is in constructing a particular type of station. The critical path programme creates an optimal schedule which could be achievable if all went well. The probability of improving on it in the course of a particular contract is very small, but, over time, learning from past experience may enable some reduction to take place. Currently the 'target' programme for all types of project assumed in the estimation of basic NECs is 72 months to first unit commissioning: any subsequent units are assumed to be commissioned at twelve-monthly intervals thereafter.

5.69. The CEGB has told us that the 72 months figure used in estimating basic NECs may be significantly different both from the first unit commissioning date assumed by the Board in its assessment of future plant/demand balances and from the contractual and divisional commitment programmes adopted by Barnwood. For the Heysham II AGR and the first PWR projects, a period of 82 months to first unit commissioning has been assumed in plant/demand balance assessments, although a 72 month construction programme will be assumed for any subsequent AGR or PWR order in the same context.

5.70. The Board has also told us that for the Heysham II project, the contract programme, which forms the basis for Barnwood's control of suppliers, is 78 months and that Barnwood's commitment to the CEGB Executive is currently based on an 82 month programme to first unit commissioning. However, this 'committed programme' remains in the nature of a target or internal management control device and does not represent Barnwood's view of the most likely outcome. Barnwood has told us that for the Heysham II project its assessment of the probability that the first unit will be commissioned within about 90 months is one in two, if the order were to be followed by other AGR orders. Otherwise the most likely outcome would be a somewhat longer period before commissioning.

5.71. We also asked Barnwood for its best estimate of construction times in the context of a long-term programme based on AGRs. It told us it believes that there would be something like a 95 per cent probability that a typical AGR in this programme would be completed within about 100 months, and that, other things being equal, average performance would improve with the length of the programme.

5.72. The Board has told us that achievement of the target construction times used in estimating basic NECs, and in the programmes which form the basis for Barnwood's commitment on Drax completion and Heysham II, would represent a very substantial improvement on past performance. The first four AGRs ordered by the Board had an average target programme of about 72 months. The average expected construction overrun on these four stations is 85 months giving a total of 157 months. The target programme for the Board's conventional stations has also been about 72 months. On the initial group of large coal-fired stations, the average delay was 27 months (giving a total construction time for each station of about 100 months). On the three large oil-fired stations currently under construction the average expected delay is 31 months (giving a total construction time of about 103 months). The Board has told us that the actions described in paragraph 5.66 are equally relevant to the improvement of construction time performance.

SENSITIVITY ANALYSES OF BASIC NECs TO VARIATION IN CONSTRUCTION COSTS AND TIMES

5.73. The CEGB has provided us with estimates of the effect on NECs (for nuclear (AGR) and coal-fired plant) of changes in the assumed construction costs and times from those calculated using the basic estimates. Table

5.6 below illustrates a series of less favourable outcomes. It may be assumed that the increase in costs is pro rata and that the effect of simultaneous increases in costs and construction times is equal to the sum of the individual variations.

TABLE 5.6 **Sensitivity analyses of basic NECs to variation in construction times and costs (£/kW per annum, March 1980 prices)**

	Nuclear (AGR)		*Coal-fired*	
Basic NECs	−18		+22	
	Change in NEC due to specified factor	*Resulting modified NEC*	*Change in NEC due to specified factor*	*Resulting modified NEC*
(1) *Construction cost* plus 15 per cent	+12	−6	+6	+27
(2) *Construction times* 2 year delay in commissioning	+13	−5	+4	+25
(3) *(1) + (2)*	+25	+7	+10	+32

Source: The CEGB

5.74. As in Table 5.5 columns (1) and (3) show the change in NEC produced by the outcome in question for nuclear (AGR) and coal-fired plant respectively. Columns (2) and (4) show the modified NECs resulting from the variation in outcomes. It should be emphasised that the figures in the table are illustrative: in particular, it is not assumed that the outcomes shown are equally likely for each type of plant.

5.75. Table 5.6 shows that the NEC of a nuclear station is significantly more sensitive to given variations in construction costs and times than that of a coal-fired plant. On construction costs, the difference arises because nuclear plant is roughly twice as expensive to build per kW sent out as conventional plant. At the same time, delays in construction are relatively more serious for nuclear plant because they lead to the deferment of the large net system savings expected once it is in operation.

(3) Plant performance variables

5.76. The key plant performance parameters identified in the CEGB's appraisal documents are lifetime rating and plant availability. The term 'lifetime' in this context refers to the level of performance achieved once the plant has settled down in operation. It is assumed that this will take three years. The significance of the lifetime rating is that if, for any reason, plant has to be operated below its design rating at any stage in its lifetime then the capital cost per kW will be higher than if it achieves its rating. The CEGB's appraisal documents distinguish between winter peak and annual average availability. While the assumption of future winter peak availability is an important determinant of the plant and planning margin in the context of investment appraisal, marginal variations in it have almost no effect on NECs of base plant load. This is because the CEGB assumes that any shortfall in winter availability due to unplanned outages will be compensated for by increased availability at other times, and so will not affect the overall annual availability. The average annual plant availability is of particular importance for base load plant, since variations in availability affect the operating cost savings which can be achieved through the displacement of plant lower in the merit order. The assumption on availability is therefore particularly important for nuclear plant since it is assumed that all such plant ordered over the next 10–15 years will operate for much of its life as base load plant.

5.77. Whereas in making forecasts of plant construction costs and times, the CEGB is able to draw to some extent on past experience, it has no equivalent experience of performance of plant over its planned design life because even the oldest of its large fossil-fired plants is barely more than halfway through its design life. Moreover, as with construction costs and times, the CEGB argues that its past experience of large fossil-fired and AGR plants is not necessarily a good guide to the performance of future plants because many of the plants ordered in the past embodied major innovations. As Chapter 12 points out the Board now favours a policy of ordering replicated designs of proven plant as far as possible. It is also noted in Chapter 12 that the Board believes that to achieve the greatest benefit from replication, there should be no more than a two-year gap between orders.

LIFETIME RATING

5.78. In estimating basic NECs, the CEGB has told us it assumes that after an initial settling-down period of three years all types of plant will achieve their design rating over the remainder of their 25–30 year operating lives. However, whilst the design rating defines an upper limit or target level of performance, the actual rating at which a plant is operated may fall short of the target, and the CEGB's experience to date with large plants has been varied. Both its large (500 MW and above) oil-fired plants have achieved their design rating but more than half of the large coal-fired stations are currently operating below their design rating. In 1979–80 the average shortfall of the seven down-rated coal-fired stations was about 3 per cent. The CEGB has told us that while it expects eventually to be able to achieve some increase in the ratings at two of these stations (Didcot and Aberthaw B), it is assumed that each will ultimately fall short of design rating. None of the CEGB's eight Magnox stations is now operated at its design rating although five of them have achieved this in the past. The interim rating agreed with NII for the Hinkley Point AGR station (and also for the similar station operated by SSEB at Hunterston) is 80 per cent. The CEGB has told us that it hopes eventually to achieve 83 per cent of design rating on this station. The 1979–80 Development Review assumes in its assessment of future generation requirements that, overall, the first four AGRs will achieve 80 per cent of their design rating, but very considerable uncertainties about their output persist and consideration has been given in the 1979–80 Development Review to the contingency that only 50 per cent rating is achieved overall by the four stations.

5.79. Although there are no PWR plants of precisely the same design as that proposed for the United Kingdom currently in operation, the CEGB's supplementary memorandum to the Select Committee on Energy referred to above describes the rating performance achieved 'on closely similar' Westinghouse plants in operation in the USA and Japan. According to this material the eight listed plants have so far achieved about 98 per cent of their designed thermal output rating. This figure is not directly comparable with those previously quoted; but the major reason for de-rating in all types of generating plant in the past (including the CEGB's plant) has been the existence of problems in the steam supply system.

AVAILABILITY

5.80. Table 5.7 below shows the CEGB's assumptions of average annual availability used in estimating basic NECs for alternative types of plant identified in the 1979–80 Development Review.

TABLE 5.7 **Assumptions on average annual availability for use in Investment Appraisal (%)**

PWR	67
AGR	68
Coal (625 MW)	66
(332 MW)	70
Gas turbines	80

Source: The CEGB's 1979–80 Development Review

5.81. The CEGB has told us that in the 1980–81 Development Review, the annual average availability assumed in estimating the basic NECs of nuclear plant has been reduced from 68 per cent to 66 per cent for AGR plant and from 67 per cent to 64 per cent for PWR. On the other hand, the Board has also told us that the annual average availability assumed in estimating the basic NECs of both 625 MW and 332 MW coal-fired plants have been increased to 71 per cent and 73 per cent respectively. In explanation, the Board has told us that the earlier estimates for nuclear plant reflected the assumption that, whilst the AGRs under construction would have the same availability as large coal units (86 per cent winter peak—66 per cent average annual), later units would benefit from the experience gained from the earlier units and would have a performance similar to that expected from oil-fired sets (88 per cent winter peak and 68 per cent average annual availability). The Board reviewed the estimates in 1980 and on the basis of available international experience of large nuclear units, retained the assumption of 88 per cent winter peak availability of PWR plant but reduced the expected annual average availability to 64 per cent to allow for off-load refuelling on an annual cycle. The Board has told us that because it believes an AGR to be 'inherently more complex' than a PWR the 86–66 per cent estimate is considered a more appropriate estimate for all AGRs.

5.82. The availability assumptions are not upper limit values in the sense that the assumption on lifetime rating is. Nor is it yet clear to what extent they would represent an improvement in performance by comparison with plant already in operation with the CEGB or other utilities. The data in Table 8.3 indicate that the assumption of a build-up to planned availability within a three year period calls for a substantial improvement over past performance of large fossil-fired plant in the CEGB's system. On the other hand, Table 8.2 also shows that the average annual availability of all of the CEGB's large fossil-fired units has averaged about 69 per cent in 1978–79 and 1979–80 and that both annual average and winter peak availability have tended to increase in recent years (with a particularly sharp gain in 1978–79).

5.83. The 68 per cent annual average availability figure for AGR plant used in the estimation of basic NECs in the 1979–80 Development Review was based on the achievement of 30 per cent on-load refuelling. The Board has told us that the figure of 66 per cent for annual average availability used in the 1980–81 Development Review is based on the assumption that full on-load refuelling will be achieved. It has also told us that the AGR availability figure is not very sensitive to the actual level of on-load refuelling achieved, and that what really matters is the achievement of sufficient on-load refuelling to avoid shutting the reactor down altogether. If the reactor had to be shut down for refuelling, then something like a six percentage points loss in annual average availability would be incurred.

5.84. The CEGB is confident that although on-load refuelling has not so far been achieved on either of the two AGR plants currently in operation (one of which is in Scotland), there is a high probability that it will be achieved eventually on at least one of its first four AGR plants, and on subsequent AGR plants. The NII, whose approval to operate on-load refuelling the CEGB must obtain, has also told us that it regards the problem of achieving on-load refuelling as soluble and that the changes in AGR design embodied in the CEGB's most recent project (Heysham II) should increase the probability of achieving at least some on-load refuelling. For this reason, the CEGB has told us that the actual availability of the AGR plants currently in operation in the United Kingdom does not necessarily provide clear guidance as to the level which may be achieved in the future.

5.85. There is very little information currently available on the settled-down availability of PWR plants of the size which the CEGB hopes to order. Some statistics on the average availability of large PWR plants designed by Westinghouse is contained in the appendix to the recent CEGB memorandum to the Select Committee on Energy. These show an average availability in 1979 of sets which have been installed for more than four years of 58 per cent. A memorandum submitted by Mr W Kenneth Davies of the Bechtel Power Corporation to the Select Committee assumes an annual availability for PWR plant of 65 per cent in an economic analysis of the costs of alternative types of generating plant.

5.86. The CEGB's investment appraisals also include assumptions about the operating life of generating plant. The 'operating life' of a plant is an inherently flexible concept. The life of conventional plant may be extended beyond whatever notional design life is assigned to it by means of plant refurbishment or life extension programmes, while the CEGB has told us that the life of nuclear plant will be dictated by its continued licensability. The

CEGB assumes that both AGR and PWR stations will achieve a 25 year life, although the Bechtel memorandum to the Select Committee referred to above assumes a 30 year life for PWR equipment in its economic analysis.

SENSITIVITY OF BASIC NECs TO VARIATION IN PLANT PERFORMANCE VARIABLES

5.87. The CEGB has given us estimates of the effects on project NECs of varying the plant performance estimates from the values assumed in calculating basic NECs. As with Table 5.6, the cases illustrated in Table 5.8 represent less favourable outcomes. The outcomes identified are not assumed to be equally probable for each type of plant.

TABLE 5.8 **Sensitivity analyses of basic NECs to variations in plant performance variables (£/kW per annum, March 1980 prices)**

	Nuclear (AGR)		*Coal-fired*	
Basic NECs	−18		+22	
Sensitivity analyses	*Change in NEC due to specified factor* (1)	*Resulting modified NEC* (2)	*Change in NEC due to specified factor* (3)	*Resulting modified NEC* (4)
(1) *Rating*				
(i) Nuclear 10% de-rating	+9	−9	—	—
(ii) Coal 5% de-rating	—	—	+2	+24
(2) *Availability*				
(iii) Annual average availability minus 3 percentage points	+6	−12	+1	+23
(iv) Winter peak availability minus 1 percentage point	+½	−17½	—	+22
(3) *Build up to target rating and availability*				
(v) 4 years	+0·3	−17½	—	+22
(4) (i) + (iii) + (iv) + (v)	+16	−2		
(5) (ii) + (iii) + (iv) + (v)			+3	+25

Source: The CEGB and Monopolies Commission

5.88. What emerges from Table 5.8 is that the NEC of a nuclear station is more sensitive to given variations in plant performance parameters than the NEC of coal-fired plant. For de-rating, this difference reflects the greater capital intensity of nuclear generating plant. As shown in Table 5.2, the capital charges component of the bssic NEC at a nuclear station is roughly twice that of coal-fired plant, and de-rating is approximately equivalent to the same percentage increase in capital costs.[1] The NEC of nuclear plant is also relatively sensitive to variations in annual average availability, first, because it is expected that nuclear plant will be run to the limit of its availability for a higher proportion of its working life than coal-fired plant and secondly because of the much alrger net system savings which its operation allows (see Table 5.2). This latter consideration also applies to the relative effects of a longer settling-down period.

[1] However, it should be noted that the effect of a 10 per cent de-rating is somewhat more than twice that of a 5 per cent de-rating.

SENSITIVITY OF BASIC NECs TO VARIATIONS IN PLANNING BACKGROUND ASSUMPTIONS

5.89. In paragraph 5.6 we explained that basic NECs are estimated against a specified planning background which includes assumptions about the growth of demand and the development of the Board's generating plant capacity. Table 5.9 below illustrates the effects on the NECs of 'typical' nuclear (AGR) and coal-fired plant of an assumption on the development of the Board's generating capacity which is different from that used in estimating basic NECs. It will be recalled that the planning background used in the 1980–81 Development Review assumes that there will be about 24 GW of nuclear generating capacity by the turn of the century. By contrast, Table 5.9 shows the estimated effect of assuming no further nuclear orders after Sizewell 'B'. The basic NEC of a nuclear station is still taken to be the same as for a typical AGR station forming one of a programme. Two variants of this case are shown. The first assumes, in line with the assumption used in estimating basic NECs in the 1980–81 Development Review, that marginal coal is available to the Board at a price corresponding to an NCB pithead price of 200 p/GJ. The second assumes that marginal coal is available at a price of 250 p/GJ cif.

TABLE 5.9 **Sensitivity analyses of basic NECs to variations in planning background assumptions (£/kW per annum March 1980 prices)**

	Nuclear (AGR)		*Coal-fired*	
Basic NECs	−18		+22	
	Change in NEC due to specified factor	*Resulting modified NEC*	*Change in NEC due to specified factor*	*Resulting modified NEC*
	(1)	(2)	(3)	(4)
No further nuclear orders after Sizewell 'B' with:				
(1) Marginal coal at 200 p/GJ (NCB pithead)	−5	−23	No change	+22
(2) Marginal coal at 250 p/GJ cif	−21	−39	−3	+19

Source: The CEGB

5.90. The effects of the specified variation in planning background on estimated nuclear NECs is shown to be favourable in each case. In explanation, the Board has told us that, other things being equal, and by comparison with the planning background used to estimate basic NECs, a lower rate of growth of nuclear capacity would result in any future nuclear station being run as base load plant for a higher proportion of its life, so achieving larger net system savings. The change in the NEC (column 1) reflects the higher value of the merit order effect as the marginal price of coal 'saved' by the introduction of nuclear capacity increases. The corresponding effect, in a very much more muted form, is apparent for coal. As with the previous sensitivity results reported in Tables 5.5, 5.6 and 5.8 the estimated NEC of a nuclear station is more sensitive to variation of this aspect of the planning background than that of a coal-fired station.

5.91. The CEGB has told us that, in principle, variations in the assumed level of future demand for electricity might affect the character of marginal plant on the system at any time, and also the marginal source and price of fuel. Other things being equal, each of these factors would affect the size of the net system saving component of the estimated NEC of new generation projects. However, the CEGB has told us that calculations in the past have suggested that the effects of relatively small variations in demand around the central estimate are small. Because it believes its current central estimates of future demand are now relatively robust, it has no recent estimates of the effects of variations in them.

The presentation of investment appraisal results and the treatment of risk and uncertainty

5.92. Our discussion of NECs has so far been in terms of only one outcome of a combination of events. In reality, given the CEGB's system model and the rate of discount applied, the values of the variables which determine the NECs are not known with certainty. In these circumstances a very important aspect of the investment decision-making process is the way in which the effects of uncertainty on estimated NECs are considered and presented. In this section of the chapter we examine how the CEGB deals with uncertainty, and how it presents the analyses internally and externally.

Internal consideration and presentation of uncertainty

5.93. The Development Review is the key internal document which presents the appraisal of alternative types of generating plant, and its analysis in turn forms the background against which the more detailed appraisal of specific individual projects is assessed. The 1979–80 Development Review contains a discussion of the treatment of risk and uncertainty in the CEGB's investment appraisal and its implications for the presentation of appraisal risks. The Review begins by drawing a distinction between the treatment of uncertainty in forecasting what are called background variables (economic activity, the demand for electricity and future fuel prices), and technical or plant related factors. For the former, the CEGB's approach is to build up a view of the probability distribution of the variables being forecast through a careful assessment of the factors which might affect the outcome. The Review states that for demand, economic activity and future fuel prices, the CEGB's Planning Department assesses the appropriate shape of the probability distribution as being the well-known normal curve.

5.94. The Review suggests that a different approach is required for the treatment of uncertainty in forecasts of technical parameters:

> 'Technical parameters such as forecast costs and construction time have a somewhat different characteristic from variables such as demand growth. Basic estimates of capital costs and construction times will in general have the nature of targets which should be quite feasible to achieve under ideal circumstances—that is to say, if the design of plant has been settled and if there is committed management and a compliant labour construction force. In practice, the best estimates are unlikely to be improved on and there is a considerable likelihood that they will not be achieved. It would be possible to try to deal with this problem by

attempting to estimate mean values of such parameters which were considerably worse than the basic or target values. For example, if the planned construction time is six years, one might estimate mean construction time at eight years within a range of six to ten years. However, this procedure would be unsatisfactory in practice since there is no rational basis for the formulation of such mean estimates.'

In explanation of this view the CEGB has said that the future course of background factors, such as coal prices, can be treated as strictly exogenous with respect to any actions taken by the CEGB, whereas technical parameters, such as construction cost and time, are subject to direct management action by the Board or its contractors. It has also told us of its fear of being seen not to be planning for success. In respect of construction times, for example, it has suggested to us that 'if you start putting longer [than target] periods in, longer periods will occur'.

5.95. Thus, the CEGB's appraisal documents present what are called 'basic' NECs built up from:

(*a*) forecasts of the mean value of background variables, such as coal prices;

(*b*) values for plant-related variables which would represent highly favourable outcomes by comparison with the Board's past experience.

The 'basic' estimates are supplemented by the results of sensitivity analysis which explore the effects of variations around the forecast mean values of the background parameters, and of failures to achieve the targets of the technical parameters. It follows, therefore, that the 'basic' estimates are not central estimates in the normally understood sense of being based on the mean or central values of all the relevant determining variables.

5.96. A chapter on Economic Assessments in the 1979–80 Development Review illustrates the CEGB's internal approach to the presentation of investment appraisal results. It sets out basic NECs for a range of alternative types of generating plant from which the conclusion is drawn that

'nuclear plant retains its clear advantage over all other competing types of plant. This is expected to persist until after total nuclear capacity on the system exceeds the system base load requirement, possibly beyond the year 2000.'

There follows a section entitled 'The Analysis of Risk and Uncertainty'. This begins by drawing attention to a table at the end of the chapter which illustrates the sensitivity of basic NECs of all types of plant to individual variations in fuel prices, construction costs and times, and plant performance variables. The economics of nuclear plant compared with coal-fired is identified as a key issue and the earlier comment on the superiority of nuclear plant is qualified as follows:

'Although the basic NECs show a substantial economic advantage for nuclear over coal-fired plant, these figures are based on probably optimistic nuclear costs (at least in the short to medium term), and on the assumption that nuclear stations will achieve forecast commissioning times, ratings, availabilities and lifetimes. The large economic advantage of nuclear [plant] is widely disputed outside the Board and even within the Board the degree of confidence in the economic advantage of nuclear plant varies considerably. It is therefore important to see just what weight of economic advantage can be ascribed to nuclear plant.'

5.97. The Board's discussion proceeds by first examining the extent to which each of the main economic parameters for the AGR and PWR would separately have to deteriorate, by comparison with the values used in estimating the basic NECs, for the nuclear NEC to increase to zero, or be in excess of the cost of maintaining marginal coal-fired plant. The latter comparison is relevant for assessing the case for investing in nuclear plant in excess of whatever additional capacity is required to meet demand growth and necessary plant retirements. The Review states that retaining coal-fired plant has a net annual cost of £12/kW per annum. These sensitivities are shown in Table 5.10 which presents the necessary change in the parameters, taken one at a time, and without adding any effects which one might have on the others.

TABLE 5.10 **The CEGB's sensitivity analysis for AGR and PWR plant**

	Increases needed to raise (negative) basic NECs to zero		*Increases needed to raise (negative) basic NECs to £12/kW per annum*	
	AGR	*PWR*	*AGR*	*PWR*
Construction cost increased by	40%	80%	60%	110%
Nuclear island cost increased by	80%	160%	120%	220%
Shortfall in rated output of	30%	45%	40%	55%
Delay in commissioning	5 years	7 years	7 years	9 years

Source: The CEGB's 1979–80 Development Review

5.98. In discussing these results, the Review points out that:

'the increase in construction costs for nuclear plant assumes that no corresponding increase in the cost of a coal-fired station would take place and of course this is very unlikely. The calculation of late commissioning assumes that the capital outlay of the station is made to schedule and without overrun, following which there is a delay of the stated number of years between completion of construction and obtaining an output. Again this is a very unlikely assumption and in practice such delays would be associated with the re-timing and overrun of capital cost.'

5.99. The second stage is then the presentation of the only combined sensitivity test for comparing new nuclear and coal-fired plant. The results are shown in Table 5.11.

The lifetime rating assumption reflects CEGB's current best estimate of what the first four AGRs will achieve. The construction time assumptions reflect the current estimates for these AGRs and experience with recent coal-fired plant, and the AGR availability figure assumes a loss of 6 percentage points because of not achieving on-load refuelling, plus a further overall 2 percentage point loss. The nuclear fuel cycle estimate represents a doubling of the estimated cost of reprocessing nuclear fuel. It will be seen that with this combination of outcomes the NECs of AGR and PWR plant exceed that of a new coal plant.

TABLE 5.11 **Development review combined sensitivity analysis**

	£/kW per annum (March 1979 prices)		
	AGR	*PWR*	*Coal*
Basic mean NEC	−26	−40	+18
Difference from basic mean NEC			
(1) Derating by 20 per cent (nuclear)	+16	+12	—
(2) Lateness of 6 years (nuclear)	+33	+33	—
(3) Lateness of 2 years (coal)	—	—	+4
(4) Average annual availability minus 8 percentage points (nuclear)	+12	+12	—
(5) Nuclear fuel plus 0·13p/kWh	+7	+7	—
Revised mean NEC	+42	+24	+22

Source: CEGB 1979–80 Development Review

5.100. In commenting on these results the Review states:

'These figures do not in themselves prove that the nuclear economic case would necessarily be inferior to coal . . .'

Attention is drawn first to the fact that basic NECs are calculated against a planning background which assumes a $1\frac{1}{2}$ GW per annum nuclear ordering programme from 1982 onwards (see paragraph 5.7). The Review states that if there were no further nuclear orders after Heysham II and Sizewell 'B' then the 'basic mean' nuclear NECs would be improved by a further £7/kW per annum.

'Indeed it could be a larger figure as the availability of the extra fossil fuel required is very uncertain.'

The Review then draws attention to other factors:

'There are further balancing sensitivities that should not be overlooked. Firstly, the cost of generation from fossil fuel is likely to increase the further into the future one goes. Secondly, technological problems can be overcome, and here the opposite principle holds: the further into the future one goes, the more likely it is that nuclear reactors will be able to operate to good levels of cost and performance.'

5.101. In the concluding chapter of the 1979–80 Review (entitled 'The Key Issues') the earlier discussion of the comparative economics of nuclear and coal-fired plant is summarised as follows:

'There is little doubt that, on the basis of current estimates of plant capital cost and performance and on future fossil fuel prices, the economics of nuclear plant are favourable compared with those of fossil plant. Indeed, new nuclear capacity appears to be justified on energy cost saving grounds alone and should provide the best hope for achieving reductions in the real price of electricity in the long term. However, the uncertainties surrounding present estimates of commissioning timescales, capital costs and performance for nuclear plant are far greater than those for fossil plant . . . The extent to which these uncertainties would erode the substantial economic benefits of nuclear plant is a matter of judgment.

However, it is clear that the establishment of a viable and effective nuclear industry is a key to the whole matter. This in turn is both dependent on and provides the incentive for a steady ordering programme of replicated nuclear plant. Certainly the Board should support any Government initiative along these lines.'

5.102. The Board has told us it recognises that, if the range of uncertainty attaching to the basic NECs differs significantly between alternative projects, then there may in certain circumstances be a case for choosing a project with a higher basic NEC but with a narrower range of uncertainty, and that its choice of turbine configuration for the first PWR plant has been made on grounds of this kind. The CEGB believes that the basic NEC of a PWR station incorporating two turbines derived from similar plant in other CEGB stations will probably be greater than the basic NEC of a station incorporating a single large MW turbo-generator (of the kind used in North American plants of equivalent rating). However, the CEGB also believes that the 'downside' risks in the use of a single very large turbine set are substantially greater than those involved in the use of close derivatives of existing proven equipment, and for this reason has preferred the 2 × 550 MW configuration for the proposed Sizewell 'B' PWR plant.

Discussion and presentation of uncertainty to bodies outside the CEGB

GOVERNMENT DEPARTMENTS

5.103. Section 8(4) of the Electricity Act 1957 provides that 'in carrying out . . . such works of development as involve substantial outlay on capital account, each of the Electricity Boards . . . shall act in accordance with a general programme settled by the Board from time to time after consultation with the Electricity Council and approved by the Minister.' Under this statutory power, the CEGB presents its capital programme as a whole to the Department each year for approval. The Department also require the Board to seek specific approval for high-cost major projects such as power stations. The information presented to the Department relating to the programme includes the plant and load position over the planning period (including forecasts of demand growth), plant decommissioning and demand to be met from outside sources, and an account of progress on major projects under way, on which the bulk of capital in any given year is spent. Information on specific projects submitted for approval includes an economic appraisal including sensitivities. The Board's programme is the subject of discussion between the Department and the Board, with the Treasury present. Further meetings and correspondence may follow. The same is true of individual projects for which approval is sought.

5.104. The Electricity Council also takes part in the discussion of the Board's programme. The Secretary of State for Energy, in announcing his policy on the future organisation of the ESI on 14 July 1980, stated that he would seek specific comments from the Council before approving capital programmes.

5.105. The Department of Energy have told us that their role in considering the investment programme of the CEGB is to check that the Board has carried out the necessary economic appraisals (though not to rework its calculations), and in particular to see whether the underlying assumptions (especially those concerning the economy as a whole) appear reasonable; whether sensitivity analyses have been carried out; whether the financial consequences are consistent with public expenditure policy; and whether the programme is consistent with the Government's energy policy. Recently the proposed investment in the Heysham II AGR has also been reviewed by the CPRS, whose report has not been published.

5.106. The CEGB has made available to us a number of documents (including notes of meetings) which illustrate the interchange between itself and Government departments (including the CPRS) both in the context of considering the overall investment programme and of Heysham II. The Board has not sent previous Development Reviews to Government Departments, but in the course of our inquiry we were informed that the 1980–81 Development Review was being supplied to the Department of Energy.

5.107. We have concentrated our attention on how investment appraisal results are presented and discussed in the interchanges with Government. Of particular importance is the manner in which the CEGB presents sensitivities. The most striking features of the documents are, first, that the sensitivities displayed are almost exclusively in terms of variations in individual parameters (such as construction cost, time or coal price); and, secondly, that examples of combined sensitivities are restricted to variations in only two factors at a time. There are no examples at all of the kind of combined sensitivity test illustrated in Table 5.11 above. There are also no examples of sensitivity tests which display the effects of simultaneous variations of fuel prices and plant-related factors.

THE CEGB'S PRESENTATION OF INVESTMENT APPRAISAL RESULTS IN PUBLISHED DOCUMENTS

5.108. Aspects of the CEGB's investment appraisal methodology (in particular, the derivation of NECs) and some results have appeared in the CEGB's 1979–80 Annual Report, and in evidence submitted by the Board to the House of Commons Select Committee on Energy. Table 5.2 shows the NECs of nuclear and coal-fired plants; it is taken from Appendix 3 (Section D) of the 1979–80 Annual Report. We have noted above that the table displays only basic NECs and not sensitivities. The Annual Report comments:

> 'The figures used for investment choice always involve a number of judgments about the relative cost and performance of the alternatives. In comparing nuclear stations with conventional stations, the most important judgments are those of the capital cost of nuclear stations (and their relative cost compared with conventional stations) and the future increase in the real price of fossil fuel. On the capital cost, the Board has no recent experience of ordering nuclear plant and has had to rely on theoretical assessments and on interpreting the data obtained from contracts placed so far for Heysham II and, on conventional plant, for the second half of Drax. The assumption used on the price of fossil fuels

is given in paragraph 12(c) above.[1] In view of the uncertainties, the Board tests the sensitivity of its central case for reasonable changes in the assumptions to ensure that the conclusions are robust.'

The Report then refers the reader for further explanation about sensitivities to paragraphs 15–26 of the CEGB Memorandum M17 to the Select Committee on Energy.

THE CEGB's EVIDENCE TO THE SELECT COMMITTEE ON ENERGY

5.109. The relevant equivalent section of Memorandum M17 is entitled 'The Economics of Nuclear Power'. It identifies the behaviour of nuclear plant cost and fossil fuel prices as the two key components in the appraisal of alternatives, and goes on to discuss the background to the estimates of those used by the CEGB. On capital costs it is stated that, although firm estimates cannot be provided at this stage,

> 'There is always the possibility of further cost escalation but, on the other hand, there are factors which might lead to a reduction in long run capital costs. Heysham II incurs launching costs and so will the PWR, but these will not be incurred on later stations. Finally current costs must inevitably reflect the dearth of recent home orders and consequent high manufacturers' overheads, and these must be expected to decrease if regular orders are placed in the future. Hence, sensitivities of plus and minus 15 per cent about the base case of £1,000/kW nuclear costs are considered, and the Board believes that settled down prices are likely to be nearer the lower end of the range. Some increases are also to be expected in the capital costs of new fossil plant particularly in view of continuing pressures to limit the environmental impact of fossil-fired stations.'

On fuel costs, the Memorandum gives the sensitivity of NECs to an increase in future coal prices of one-half the increase estimated in the basic case. The results of these individual sensitivity tests on capital cost and coal prices are shown in Table 5.12.

TABLE 5.12 **Net effective costs of new stations £/kW per annum (March 1980 prices)**

	Nuclear plant	*Coal-fired plant*
Basic NEC	−23	+21
NEC if: Nuclear construction cost +15%	−10	+21
Nuclear construction cost −15%	−36	+21
Coal-fired construction cost +15%	−23	+27
Coal-fired construction cost −15%	−23	+15
Coal prices increase of only half that assumed in the base case	+9	+27

Source: The CEGB's Memorandum M17 to the House of Commons Select Committee on Energy

[1] It has been assumed that nuclear fuel cycle costs increase by nearly 2 per cent a year in real terms. For fossil fuel prices it is assumed that the real cost of coal rises at an average of 3 per cent a year from now to the end of the century and that of oil by 3½ per cent a year.

5.110. In response to a request from the Select Committee, the CEGB submitted a further memorandum (M29) on investment appraisal methodology which includes a combined sensitivity exercise presented in the following way:

> 'If it is assumed that there is three years' lateness in the construction of nuclear plant together with an increase in capital costs of 50 per cent per kW, then the NEC is increased from £−23/kW per annum to £+25/kW per annum. Any lateness and increase in capital costs are unlikely to be restricted to nuclear plant but would affect coal-fired plant to a greater or lesser degree since they are related in part to problems associated with construction on any large site and to manufacturers' overall efficiency and levels of profitability, as well as to problems associated with particular technology. With similar lateness and increase in capital cost the NEC of coal-fired plant would increase from £+21/kW per annum to £+44/kW per annum.'

Refurbishment

5.111. As explained in paragraph 5.86, the operating life of plant is not fixed and this flexibility is useful for matching supply and demand in the short term. The CEGB has told us that in practice the life of power stations is governed much more by operating hours than by calendar years, and because of differences in delivered fuel costs, plant efficiencies and availabilities, the accumulation of running hours on a given group of plant may be spread quite widely. Thus, the period over which plant is retired may be spread much more widely than might be suggested by age in calendar years.

5.112. The CEGB is engaged in a long-term exercise which is aimed at identifying the role of plant refurbishment and its life extension. It has told us that this work started in 1974 when studies of running hours indicated that, because of its higher lifetime load factor, the 60 MW group of plant would reach its nominal design life at about the same time as the 30 MW plant. Because it was thought that there might be difficulties in making good the subsequent loss of generating capacity, studies were initiated to assess the engineering problems of life extension. A Working Group was set up in the Board's Midlands Region and this came to the conclusion that there was no technical reason why, in general, plant life should not be extended. In its current work on plant refurbishment the CEGB is examining the technical and economic implications of keeping plant of 100 MW capacity and above in service for up to 250,000 hours of operation or 50 years. Although certain tentative conclusions have been reached, the CEGB emphasises that more follow-up work by research and operational staff is required for the establishment of improved techniques of measurement and component life prediction.

5.113. In the same way as a 'system background' is created in the appraisal of alternative generating plant options an economic assessment of refurbishment carried out by the Board in 1980[1] made a set of initial assumptions

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[1] The study was carried out after the completion of the 1979–80 Development Review and before the completion of the 1980–81 Review.

about the growth of demand, the prospective development of new generating capacity and the retirement of existing capacity for a period up to the late 1990s. These were:

(i) that the growth in demand for electricity assumed in the ESI's February 1980 adopted forecast was extended to the late 1990s;

(ii) that about 17–18 GW of nuclear plant (the initial AGR and PWR orders followed by the 15 GW programme) would be added to the system in addition to the AGR and conventional plant currently under construction;

(iii) that the 30/60 MW sets currently on the system would be retired after 40 years' life; and that Magnox plant would be retired after a 25-year life.

5.114. Given these assumptions, the Board's economic assessment of refurbishment examined the choice which the Board might face in the mid-1990s between retiring 500 MW stations at the end of their 30 year design lives (in which case they would have to be replaced by new coal-fired stations) and maintaining them in operation beyond the end of their 30 year life. The Board has explained to us that in the mid-1990s it expects that the annual net system saving associated with the retention of high merit order coal-fired plant will be similar to that associated with new coal-fired plant. It pointed out that its economic assessment therefore reduced to a comparison of the difference between the annualised present value of repair and maintenance (R and M) costs of new plants and the annual R and M costs of life-extended plants on the one hand, and the capital charges associated with new plants on the other (see Table 5.2).

5.115. Analysis by the Board's operating regions of R and M expenditure indicated the likelihood of significant inter-plant variations in the cost of repair and maintenance; the economic assessment was therefore based on a notional division of the plant population into standard and high cost categories. For the latter, it was assumed that annual availability would be reduced by 6 percentage points during the whole of the period beyond the plant's normal working life. Reduced availability for high cost plant during its extended life implies a reduction in overall system thermal efficiency because of the need to operate lower merit order plant as replacement.

5.116. The CEGB has told us that its economic assessment of refurbishment indicated that the increased level of annual R and M costs which might be incurred in stations beyond the end of their 30 year design lives compared to those of new stations averaged over a 30 year life, is very much less than the capital charges associated with new plant. Specifically:

(i) the net avoidable cost for life extension of 'standard' coal-fired plant is estimated as £23/kW per annum lower than the basic NEC of new coal-fired plant (estimated in the 1980–81 Development Review to be £22/kW per annum);

(ii) the net avoidable cost for life extension of 'high cost' coal-fired plant is estimated as £18/kW per annum lower than the NEC of new coal-fired plant.

On the other hand the Board estimates that the net avoidable cost of refurbishing oil-fired plant is greater than the NEC for new coal-fired plant.

5.117. The CEGB has concluded that it can base its plans for the development of its generating capacity on the assumption of a 40 year life for 500 and 660 MW coal-fired stations. It concludes that there is no case for refurbishment of its oil-fired capacity. The Board has emphasised to us, however, that the results of the economic assessment should not be taken to mean that replacement of old plant can be postponed indefinitely. It believes that the need for major structural repairs etc will eventually make it more economic to replace old plant with new. The CEGB has also told us that a rigid policy of extending life to 50 years or 250,000 hours of operation could mean that by the end of the century as much as half the plant on the system would be over 30 years old. This would represent a significantly higher proportion of elderly plant than at any time in the past. The Board points out that it would be in unknown territory, especially since the modern plant whose life would need to be extended would be operating under conditions of which no experience exists. It argues that life extension would carry a risk of unforseen faults arising in the later life of the plant. Because their incidence would be difficult to predict and because of fears about the effects of an uneven incidence of faults on plant manufacturers' workloads, the Board considers it unwise, even over a limited period, to look to refurbishment alone to ensure there is adequate plant capacity on the system. It would not therefore seek to refurbish all existing high merit fossil-fired plant.

Plant conversion

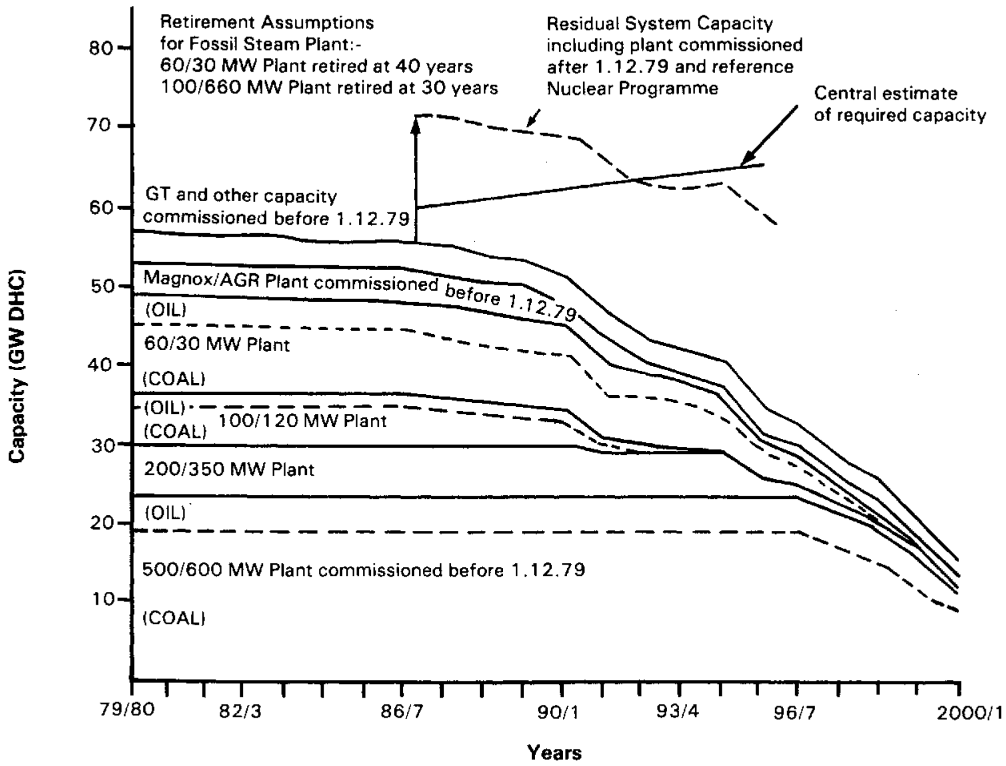
5.118. The Board has told us that there may be a case for reconversion to coal firing of some plant initially designed to burn coal but currently burning oil. In contrast to life extension, reconversion would lead to some loss of availability whilst the necessary capital expenditure (primarily on boiler conversion) was undertaken. So far, only a general economic assessment of reconversion has been undertaken, but more detailed studies are in hand of the economics and feasibility of reconversion of several of the Board's 100/120 MW units. The Board has also said that some of the 500–660 MW oil-fired units would not be suitable for conversion because of a lack of space for the necessary larger boilers and precipitators as well as coal storage. There are also other environmental constraints associated with the transport of coal to the sites and the disposal of ash.

5.119. If oil-fired plant is not converted, the CEGB has said there may be a case for a modest programme of investment in new coal-fired plant with orders commencing in the first half of the 1980s, in order to support the system until a higher rate of commissioning of nuclear plant has been achieved. Figure 5.2 shows the forecast plant-demand balance until the turn of the century, on the assumptions set out in paragraph 5.113; the forecast suggests that if the 17–18 GW programme of nuclear plant is the maximum possible, unless reconversion and refurbishment is undertaken, a shortfall of plant will appear and rapidly increase.

FIGURE 5.2

System Capacity and Demand Estimates

Source: CEGB



The CEGB's presentation of the case for long-term nuclear investment

5.120. In paragraphs 5.92–5.110 we have drawn attention to certain features of the CEGB's presentation of investment appraisal material both internally and externally. We now consider how robust is the economic case for the CEGB's currently preferred nuclear investment programme. In doing so, we are aware that the Board has emphasised to us that its decisions on major issues, such as the choice of generating plant, do not rest solely on the numerical results of investment appraisal but involve very difficult matters of judgment both economic and strategic. We feel justified in doing so however because the Board's case for nuclear investment is overwhelmingly an economic case. It argues that, given the expected development of demand for electricity and the availability and operating cost of generating plant currently and prospectively on the system, such a programme will lead to lower electricity prices in the long run than either a smaller nuclear programme or a programme based on coal-fired plant. The Board also emphasises that a nuclear strategy of the kind it wishes to pursue will have important benefits in terms of system flexibility and insurance against possible non-availability of alternative fuels.

5.121. The 1979–80 Development Review discusses the merits of a long-term nuclear ordering programme of about 1½ GW per annum from 1982 onwards. Anticipating a major announcement from the Government on a future United Kingdom nuclear programme, the Review states that:

> 'The Board should strongly support such a programme both on long-term energy supply and economic grounds.'

In the event of the Government not announcing its commitment to a long-term programme the Review suggests that:

> 'In such circumstances, we see no reason for not pursuing our present strategy of developing nuclear capacity as quickly as practicable, and we could continue to plan on a nuclear programme of about 1½ GW per annum or more.'

5.122. In the event, the Secretary of State said in his statement to the House of Commons in December 1979 *inter alia:*

> 'We believe that there must be continuing power station orders if our long-term energy supplies are to be secured and current industrial uncertainties are to be resolved. The last Government authorised the CEGB and the SSEB to begin work at once with a view to ordering one advanced gas-cooled reactor station each as soon as possible. This is in hand.
>
> The last Government also endorsed the intention of the CEGB to establish the pressurised water reactor as a valid option . . .
>
> This Government agree that the nuclear and electricity supply industry should now proceed along these lines, and we have made clear to them our wish that, subject to the necessary consents and safety clearances, the PWR should be the next nulcear power station ordered, with the aim of starting construction in 1982.
>
> Looking ahead, the United Kingdom electricity supply industry has advised that even on cautious assumptions, it would need to order at least one new nuclear power station a year in the decade from 1982,

or a programme of the order of 15,000 MW over ten years. The precise level of future ordering would depend on the development of electricity demand and the performance of the industry, but we consider this a reasonable prospect against which the nuclear and power plant industries can plan. Decisions about the choice of reactor for later orders will be taken in due course.'

The Board has told us that it strongly welcomes this statement.

5.123. In assessing the case for the long-term programme of the size indicated in the Secretary of State's statement and anticipated in the 1979–80 Development Review, we think it is important to establish whether, and if so to what extent, it would involve ordering in advance of need—defined as the necessary minimum level of investment required to meet future growth in demand and to replace plant which is strictly life-expired. In investing to meet forecast shortfall in capacity, the Board must compare, in present circumstances, the expected NECs of new nuclear and coal-fired generating plant. If the new generating capacity is not required on capacity grounds, however, the Board has told us it must compare the expected NEC of the new plant with the net avoidable cost of maintaining existing fossil-fired capacity on the system, or in certain circumstances, the costs of refurbishing existing fossil-fired capacity in order to extend its operational life. The second test is the more stringent in present circumstances because the net avoidable costs of maintaining existing plant on the system and also of refurbishment (see paragraph 5.116) are less than the estimated basic NEC of new coal-fired plant.

5.124. Current electricity supply industry demand forecasts assume a growth of peak demand in the late 1980s of just over 1 per cent per annum. Additionally, the 1979–80 Development Review states that the minimum unavoidable level of plant closures is about 300 MW per annum. On this basis, the Board's gross requirement for new generating capacity, given a 28 per cent planning margin, might be about 900 MW per annum in the late 1980s and early 1990s. A rate of gross investment of 1500 MW per annum would therefore enable a higher level of plant closure to be undertaken for any given level of demand. The 1979–80 Development Review suggests that a 1500 MW per annum ordering programme from 1982 onwards might allow a plant closure rate of about 900 MW per annum. On the other hand, if the start of the 1500 MW per annum ordering was deferred to 1984, then this would allow a closure programme of about 600 MW per annum. It would seem that a substantial proportion of a 1500 MW per annum programme would represent investment in advance of need.

5.125. In line with our examination of the Board's presentation of investment appraisal results we asked the Board to re-estimate the NECs of a typical AGR and new coal-fired plant using a set of specified assumptions on some of the determining variables which did not represent target levels of achievement. The CEGB has told us that, in each case, the appraisal is based on a planned first unit commissioning date in the early 1990s. The 'typical' AGR plant is assumed to be the fourth or fifth of a series and the 'typical' coal-fired plant would be similar to the one at Drax completion.

5.126. The assumptions which we asked the CEGB to make and a comparison with those underlying the estimation of basic NECs are shown in Table 5.13.

TABLE 5.13 **The CEGB's basic estimates and alternative assumptions (March 1980 prices)**

	*CEGB**	*Alternative*
(i) Nuclear fuel cycle costs (contribution to NEC)	£40/kW sent out	£48/kW sent out (ie +20%)
(ii) Plant related factors		
(*a*) Cost of nuclear plant (contribution to NEC)	£78/kW sent out	£86/kW sent out (ie +10%)
(*b*) Construction time of nuclear plant	6 years	8 years
(*c*) Cost of coal-fired plant (contribution to NEC)	£35/kW sent out	£37/kW sent out (ie +5%)
(*d*) Construction time of coal-fired plant	6 years	7 years
(iii) Plant performance variables		
(*a*) Nuclear plant annual average availability	66%	65%
(*b*) Nuclear plant winter peak availability	86%	85%
(*c*) Nuclear plant lifetime rating	100%	95%
(*d*) Build up to full rating and availability	3 years	4 years
(*e*) For coal-fired plant we asked the CEGB to use its own estimates for the alternative assumptions.		

Source: The CEGB and Monopolies Commission

* The figures are those used in the 1980–81 Development Review.

Our comments on the status of the alternative assumptions (whose implications we have asked the CEGB to examine) are as follows:

(i) NUCLEAR FUEL CYCLE COSTS

The CEGB has told us that the estimate of nuclear fuel cycle costs underlying the basic NECs presented in the 1980–81 Development Review is 15 per cent higher than the estimate used in the production of the 1979–80 Review estimates. We believe that it is reasonable to expect some further real increase in the light of the uncertain basis of some of the underlying cost estimates, of past experience, which has been one of persistent real cost increase, and what the CEGB itself recognises as major uncertainties.

(ii) PLANT RELATED FACTORS

In line with the comments (quoted in paragraph 5.98 above) in the 1979–80 Development Review we assume that any excess over target construction time will be associated with some construction cost overruns. Our assumption on AGR construction times in particular represents a substantial improvement on past performance, and is therefore very much less 'pessimistic' than the outcome assumed in the combined sensitivity run displayed in the 1979–80 Development Review (see Table 5.11). The assumption on coal-fired plant would represent something like a 10 per cent reduction in the average construction time achieved in the past.

Our assumptions on construction costs for both nuclear and fossil-fired plants are also intended to recognise the very real risk of some further real cost escalation. This view represents the balance of a number of separate tendencies. Amongst those making for some increase in costs we have identified safety and environmental factors and the persistent historic tendency towards real cost inflation identified in the discussion of construction costs in paragraph 5.63.

The CEGB has told us that it expects the safety requirements for new nuclear plant will eventually become settled. The NII has told us it agrees. However, it is difficult, perhaps impossible, to predict when this will take place and at what level of requirement, since the public's perception of the risks of accidents seems to be ever changing. Until stability has been achieved there is a clear risk that costs will rise with each new plant. Moreover, a future programme of AGRs of the size envisaged, were PWR to fail at the Sizewell public inquiry, would face an already foreseeable difficulty, which the CEGB is aware of. The NII has told us that before it could agree to license the design for a larger future AGR programme it would have to be assured that Heysham II's design could not practically be improved upon. The NII has told us that it does not yet believe that this condition is satisfied in respect of certain basic elements of the gas cooling system. The CEGB has told us that further developments of this aspect of AGR design would involve extensive re-design of the entire AGR nuclear island, and the strong probability of further real cost escalation.

The CEGB has told us that there is some risk of escalation in the capital costs of coal-fired plant arising from pressure to remove sulphur from flue-gas emissions. The Board believes that if it was obliged to do so then this would add as much as 25 per cent to the capital costs of coal-fired plant. We note that by comparison with North America, where there is currently much environmental pressure for the removal of sulphur, United Kingdom domestic coal resources have a relatively low sulphur content. We also note that the Board's chairman in a speech in February 1980 has suggested that there was a strong possibility of current research demonstrating that the (claimed) adverse consequences of sulphur emission had been much exaggerated.

Against these considerations must be set the potential advantages arising from a steady ordering programme. In this context, the CEGB has told us that recent French experience of a programme of PWR orders indicates that a unit cost saving of about 8 per cent is achievable by the fifth order in the series.

The difference between 5 per cent and 10 per cent addition to coal-fired and nuclear capital costs is intended to represent our necessarily rough judgment about the relative impacts of the factors we have discussed on the two types of plant.

(iii) PLANT PERFORMANCE VARIABLES

Our assumptions on nuclear plant performance are primarily what we would call prudent allowances for things not going absolutely right. In support of the view that it is appropriate to make allowances of this kind with relatively novel technology, we would point to the current uncertainty surrounding the future rating of AGR equipment and the relatively slow build-up to planned levels of availability experienced with both AGR and PWR equipment.

5.127. We asked the CEGB to use whatever was its current central case assumption on marginal fossil fuel prices in estimating the modified NECs. The CEGB has told us that the figures are based on an assumption that coal will be available to it at the margin at a price equal to its present central case assumption on NCB prices. Given its central case assumption on future availability of NCB coal, there would be a requirement for about 8 million tonnes a year of imported coal in these circumstances. Alternatively, if the availability of NCB coal to the Board were more than about 60 million tonnes a year at the turn of the century, then all of the CEGB's requirements could be met by domestic supplies.

5.128. The results of the combined sensitivity test are shown in Table 5.14 together with the separate effects attributable to each of the individual outcomes identified. We see that on this basis the NEC increases from the basic estimate of £−18/kW per annum for nuclear and £+22/kW per annum for coal to £+20/kW per annum and £+25/kW per annum respectively (at March 1980 prices). The CEGB has told us that the net avoidable cost of maintaining fossil-fired plant (with which the NECs of either new nuclear or new coal-fired plant should be compared) would be about £10/kW per annum in the early 1990s (the mid point of a range from £5–£15/kW per annum). The net avoidable cost associated with plant refurbishment (see paragraph 5.116) would be about £−1/kW and £+4/kW per annum for standard and high cost plants respectively in the mid-1990s.

5.129. We have not presented any equivalent figures for PWR plants. Our reluctance to do so stems mainly from a statement in the 1979–80 Development Review to the effect that:

> 'current coal station capital costs, being based on recent tender prices, are more realistic (ie relatively greater) than AGR costs which, in turn, are more realistic than PWR costs.'

The PWR cost underlying the Board's present estimates of basic NECs are based on an updating of estimates produced in 1977 for the Thermal Reactor Assessment. We have already seen that the equivalent figures for AGR costs have turned out to be very substantial under-estimates. We are also aware that the CEGB has told us that a PWR programme, at least initially, will incorporate all the safety features that the licensor has included in the design he is selling worldwide, and that these are still to some extent undetermined. Worldwide concern in the event of any accident or incident affecting a PWR anywhere would therefore have an effect on the PWR design used in the United Kingdom whatever the NII policy. On the other hand, we are also aware of certain factors which were not adequately reflected in the Thermal Reactor Assessment estimates. In particular, there is the possibility of importing certain nuclear steam supply system equipment at favourable prices, given current and anticipated excess capacity worldwide.

TABLE 5.14 **Results of the combined sensitivity test £/kW per annum (March 1980 prices)**

	NEC of 'typical' AGR	*NEC of 'typical' coal-fired plant*	*Net Avoidable Cost of maintaining old plant in early 1990s*
1980–81 Development Review estimate	−18	+22	+10
Result of combining alternative assumptions	+18	+25	+10
Contributory effect of:			
(i) Nuclear fuel cycle costs +20%	+8	—	—
(ii) (*a*) Construction cost of nuclear plant +10% and (*b*) Construction cost of coal-fired plant +5%	+8	+2	—
(*c*) Completion time delay 2 years for nuclear and (*d*) Completion time delay 1 year for coal-fired	+13	+1	—
(iii) (*a*) Nuclear annual availability 65% (−1% point)	+2	—	—
(*b*) Nuclear winter peak availability 85% (−1% point)	+0·5	—	—
(*c*) Nuclear lifetime rating 95% (−5%)	+4	—	—
(*d*) Nuclear build up to rating and availability 4 years not 3 years	+0·3	—	—

Source: The CEGB

THE CASE FOR HEYSHAM II

5.130. In contrast to the case for the long-term 15 GW programme, the CEGB has told us that the primary justification for proceeding with an AGR order (as well as an order for PWR equipment) is more strategic in nature (see paragraph 4.2): as we have seen, the Board argues that a long-term programme of nuclear plant construction (whether based on AGR, PWR or both types of equipment) offers the best prospect for containing the real rate of increase of electricity prices. However, until the results of the Sizewell B public inquiry are known, the Board cannot be certain whether, or under what conditions, it would be possible to use PWR technology in the long-term programme. Moreover, the Board has told us that it will not be in a position to choose between the alternative systems until it has experience of ordering and constructing PWR stations. In these circumstances, it is argued that a failure to proceed with an AGR order (or orders) would put at risk the United Kingdom's capability to take up the AGR option in the future, should it prove necessary to do so, either because of the outcome of the public inquiry, or because early experience with PWR ordering and construction does not meet expectations. In the Board's view, the key element in this capability which would have been at risk if no order or orders had been forthcoming is the current AGR design and development capacity of the NNC and the boiler manufacturers.

5.131. The Board has told us that the estimated cost of Heysham II to the Board might have been about 20 per cent higher if SSEB had not placed a simultaneous order for a similar AGR station. It has also told us that in its view a single AGR order might have led to a loss of skilled manpower from NNC with further adverse effects on the duration and cost of the project.

5.132. In commenting on the development of the case for ordering Heysham II, we are not in a position to offer any judgment on the validity or otherwise of the 'strategic' arguments, which may, in the context of this particular decision, have taken on an overriding importance in the minds of the Board and Ministers. However, in addition to the strategic case for ordering Heysham II, the CEGB has told us that the decision is also justifiable on cost-saving grounds, and this combination of long-term strategic and cost-saving arguments has been deployed in making the case for the Heysham II investment to Government.

5.133. The Board has said that planning margin considerations would not be relevant to a decision to order Heysham II and that the alternative to proceeding with its construction would be the deferment of marginal plant closure. The Board has told us that, in present circumstances, the net annual cost of deferring closure would be about £10/kW per annum at March 1980 prices, and this is the figure with which the estimated NEC of Heysham II must be compared.

Conclusions

Basic framework of investment planning and appraisal

5.134. We found that the CEGB employs considerable technical expertise in the development of the computer programs which allow a comprehensive assessment of the effects of a particular investment project to be made on the basis of specified estimates and assumptions. However, the value of these assessments depends on the validity of assumptions on certain key variables which we discuss below. The programs are sufficiently developed to be able to cope with the calculations of combined sensitivities without any substantial modifications, and are therefore a potentially most useful planning tool.

5.135. The Board's current application of a 15 per cent required rate of return in conjunction with a 3 year payback period to the optional investment category is a rationing device which introduces the risk of some misallocation of its investment resources. Heysham II, the economic justification of which is that it is expected to reduce costs, was evaluated against a more lenient test (a 5 per cent rate of return over its lifetime) than other types of potentially cost-saving projects, such as national spares.

Forecasting key variables

5.136. On present plans, the Board is unlikely to be a major user of oil or gas in the future, and in any event relies heavily on outside opinions on the development of the oil market. Our conclusions are therefore confined to evaluation of the forecasting of coal prices and availability and nuclear fuel cycle costs.

Coal prices and availability

5.137. The sensitivity analyses reported in Table 5.5 show that the choice of generating plant is highly sensitive to variations in the forecast price of coal at the margin to the CEGB. We have therefore examined the Board's forecasts in some detail and draw attention to certain inconsistencies in its approach.

5.138. The Board has told us that around the end of the century it expects to be able to purchase only about 55 million tonnes of coal a year from the NCB at a pithead price of about 200 p/GJ, compared with its current purchase of about 75 million tonnes a year at about 125 p/GJ. Underlying the Board's prediction is an expectation that industrial and commercial demand for coal will grow, especially in the 1990s; at the same time the Board believes that, notwithstanding this increase in demand, NCB output will decline by about 5 per cent from its current levels. We note that the Board's expectations for NCB output are significantly more pessimistic than those of the Department of Energy whose views we have sought.

5.139. The Board has told us that, given the planning background assumed in the 1980–81 Development Review, it expects to burn about 63 million tonnes of coal a year around the turn of the century, compared with a 1979–80 coal burn of about 81 million tonnes. The difference between the expected burn of 63 million tonnes and the figure of 55 million tonnes which the Board expects to be 'available' from the NCB would be supplied by coal imports.

5.140. The Board has said that its current central estimate of the price of imported coal around the turn of the century is about 300 p/GJ delivered. We find this forecast of a 40 per cent price differential between imported and domestic coal prices to be highly implausible. We believe that if the world market price were to rise as high as the CEGB expects, then it would be unrealistic to suppose that the NCB's prices would not be significantly higher than the Board's current central forecast. Moreover, if, for whatever reason, a significant difference in favour of domestic prices were to develop as the Board expects, then we should also expect the CEGB to bid for a higher share of the NCB's output. In this context, we find the concept of an 'availability' of NCB coal unrelated to price to be unsatisfactory. We believe that the forecast of domestic and imported coal prices contained in the 1979–80 Development Review (in which the forecast difference between NCB and imported coal prices around the turn of the century was very small and in favour of imported coal) represents a more internally consistent view than the current forecast.

5.141. We draw attention to the fact that a very significant change in its expectation about the future course of the sterling exchange rate underlies the Board's revision of its view on the development of imported coal prices between the 1979–80 and 1980–81 Development Reviews. We also note that although the Board appears to share the views of the WOCOL study about the way in which the world coal market will develop over the next 20 years, the Board's expectation on the potential volume of world coal trade around the turn of the century is markedly more pessimistic than that of the WOCOL contributors.

5.142. If the Board expects to have a substantial requirement for imported coal over the long-term we should expect it to have developed firm proposals for securing a long-term position for itself in the world coal market. The Board's lack of initiative in this respect contrasts strongly both with its enterprise in seeking out long-term sources of uranium supply in the context of its nuclear programme, and with the behaviour of coal-burning electricity supply utilities in other parts of the world.

5.143. In view of the great importance of coal prices and availability in the Board's choice of generating projects, we find the weaknesses in forecasting on which we have commented to be a cause for concern. We recognise that the task of forming a judgment on these matters is complicated by the particular difficulties in the Board's relations with the NCB, to which we draw attention elsewhere, and by the real uncertainty over the extent to which the Board will be allowed to act as a free commercial agent in coal importation. Nevertheless, we strongly recommend that the Board should devote more time and effort to developing an internally consistent view of the future prices and availability of both domestically produced and imported coal. In doing so we should expect the Board to consult closely with the Department of Energy. The latter's role as sponsoring department for the energy industries may enable them to supplement the expertise on the working of the relevant markets which is available within the Board.

Nuclear fuel cycle costs

5.144. We recognise that in attempting to forecast the future level of nuclear fuel cycle costs, the Board faces significant uncertainties about the development of the market for uranium and in the area of reprocessing costs. There is some exploration of the uncertainties in the 1979–80 Development Review. However, we find it surprising, especially in view of the basis of the Board's current relationship with BNFL (see Chapter 7), that the Review does not systematically explore the effects on nuclear fuel cycle costs of achieving a level of nuclear generating capacity which is less than that assumed in the 'planning background' nuclear programme. We note that the estimate of nuclear fuel cycle costs underlying the basic NECs produced by the Board has very recently been increased by 15 per cent over the level assumed in the 1979–80 Development Review. We recommend that, until further figures are available from the Board's own work, and from BNFL on AGR and PWR reprocessing costs, a sceptical attitude towards nuclear fuel cycle costs is appropriate in investment appraisal work.

Construction costs and time

5.145. In paragraphs 5.162–5.165 we argue that the CEGB's investment appraisal should focus on estimates of NECs incorporating the most realistic or likely outcome with respect to construction costs and time rather than estimates which incorporate target levels of performance.

5.146. In developing estimates of construction costs for use in investment appraisal we recommend that explicit account should be taken, first, of market conditions in the supply of major items of plant equipment, and secondly, of relative price effects during plant construction. There is evidence that the CEGB's power station construction programmes have suffered from persistent real price increases. We find it surprising, in view of this experience and the very long construction period of generating projects, that the CEGB has been unable to provide us with any analysis of this phenomenon.

5.147. In general, we endorse the CEGB's approach to building up estimates of construction costs by means of a basic cost estimate to which a start-to-finish allowance is added. However, we believe that its current practice of assuming a common start-to-finish allowance for both nuclear and conventional generating projects is unsound. In coming to this view, we are mindful of the CEGB's past experience, which has been one of significantly different rates of cost overruns between different types of project; the CEGB has also told us that it is near the top of its learning curve for coal-fired plant. It has made no similar claims about AGR plants, and it has no experience at all of constructing PWR plants. Recent experience in AGR construction and the potential additional risks arising from unexpected changes in safety etc standards requiring design modification in the course of construction would suggest that the start-to-finish allowance for nuclear projects should be larger than for conventional projects. We therefore recommend that the Board should adopt a larger start-to-finish allowance for nuclear projects than for conventional projects.

5.148. We have seen that the project construction times assumed in the basic NEC estimates are targets. We have noted that these target construction times are shorter than the estimated contract programme, and the programme which forms the basis for the Barnwood commitment to the CEGB's Executive. We also note that in the case of the first AGR and PWR stations, the Board has assumed a longer period to first unit commissioning in assessing prospects for the future plant-demand balance than it used in investment appraisal documents, and even this longer period is less than Barnwood's own estimate of the most likely outturn construction time.

5.149. The prediction of construction time is important because construction time affects project NECs through the deferment of system benefits and the additional interest incurred during construction, and through their effects on construction costs. We therefore recommend that this aspect of the CEGB's work on project appraisal should be improved as a matter of urgency. The Board should investigate whether more elaborate methods might usefully supplement the critical path analysis which forms the basis for estimating the target construction time. These methods would allow explicit estimates of the likely (rather than target) time needed for each task to be aggregated, so as to produce an overall most likely estimate; moreover they would allow the systematic exploration of the effect of assuming higher or lower risk for each task.

Plant performance

5.150. All types of plant are assumed to achieve target design rating after an initial proving period. We believe that experience to date with gas-cooled reactor systems would suggest a more conservative estimate than 100 per cent should be used on the central estimate in the appraisal of AGR plant until the technology involved is better established and proven in operation.

5.151. The CEGB's recent experience with large conventional sets suggests that the probability of achieving the level of annual availability assumed in the investment appraisal documents is high, and indeed the CEGB's assumption might be described as cautious. Similarly its assumption that new coal-fired plant would achieve 86 per cent winter peak availability is consistent with past experience. The assumptions for nuclear plant are perhaps more optimistic. We have seen that the CEGB's latest assumptions on annual average availability for future AGR plant are based on the achievement of full on-load refuelling. The NII believe that there is a high probability of achieving some degree of on-load refuelling in the future, although so far no on-load refuelling has actually been achieved.

5.152. The CEGB assumes that a three year period is required to bring new plant up to full rating and availability. We have noted that this would represent a substantial improvement on past performance, and that in the case of nuclear plant NII's approval is required before a settled-down operating regime can be established. We recommend that a realistic central estimate should reflect past difficulties and therefore involve a more cautious judgment than the CEGB's.

The presentation of investment appraisal results and the treatment of risk and uncertainty

5.153. The CEGB's investment appraisal documents present so-called basic (or central) estimates of NECs. These incorporate forecasts of the mean values of background variables (such as fuel prices). On the other hand, the forecast values of technical parameters (such as construction times) are in the main either limiting values or targets, the achievement of which would represent a significant improvement on past performance. The Board itself recognises this and acknowledges that the basic NEC is not a central estimate in the normally understood sense—ie one which is based on the central or most likely estimates of all the relevant determining variables. In these circumstances a very important element in the appraisal process is the way in which the sensitivity of the basic NEC to failure to achieve targets or limiting values is explored and presented both internally and externally.

5.154. The discussion of key variables in paragraphs 5.136–5.152 suggests that taking the planning background as given, sensitivity tests should at least display the combined effects on project NECs of the following outcomes:

(i) simultaneous construction time and cost overruns;

(ii) further real cost increases in nuclear fuel cycle costs;

(iii) some shortfall in several of the plant performance targets (such as rating or settling-down period).

The discussion of the CEGB's past experience (for example in paragraphs 5.62, 5.72 and 5.78) also strongly suggests that the degree of shortfall from target which should be explored in sensitivity tests should be systematically different for different types of plant. For example:

(i) the extent of failure to meet target construction times and costs appears to increase with the novelty of the plant under construction;

(ii) the risks of failure to achieve and/or maintain design ratings appear to be greater for gas-cooled nuclear steam supply systems than for other types of steam supply system.

5.155. The CEGB's past experience also suggests that the risk of adverse performance simultaneously occurring on several features of plant operation is also systematically related to the nature of the project. Plants incorporating novel design features (such as the first four AGRs) are more likely to experience unforeseen problems not only in construction but in performance than plants of mature design. Once again the characteristic of plants should also find recognition in the type of sensitivity result presented.

5.156. In addition to displaying the combined effects of failure to achieve targets across a range of technical parameters, we think sensitivity results should also display the effects of varying assumptions on fuel prices and availability and of the planning background itself. In view of the importance of coal prices we suggest that one particularly useful type of sensitivity test would be to show the rate of growth of coal prices at which the NECs of coal-fired and nuclear plant were equal, keeping the values of the other variables constant. In view of the discussion of the planning background in paragraphs 5.89–5.91 we consider that sensitivity analysis should also explore the interaction of simultaneous variation in planning background and fuel price assumptions on project NECs.

PRESENTATION OF RESULTS IN INTERNAL DOCUMENTS

5.157. The 1979–80 Development Review contains a number of individual sensitivity analyses but only one combined sensitivity test, the results of which are presented in Table 5.11, for comparison with the basic NEC estimates. In our view attention should be drawn at some point in a document such as the Development Review to outcomes which lie between the basic estimate and the rather adverse set of circumstances represented by the combined sensitivity test. We believe that the material in the relevant chapter of that Review represents a seriously inadequate treatment of problems of great magnitude and falls short of what one might expect to find in a document of this kind. We also find the introduction of material on the planning background (which itself is not thoroughly discussed elsewhere in the chapter) to be potentially confusing. The effect of varying the planning background is sufficiently important to warrant separate analysis.

EXTERNAL PRESENTATION OF RESULTS

5.158. In the exchanges between the Board and Government which we have seen, we have found no evidence that the Board has displayed anything like the combined sensitivity test reported in Table 5.11 *et seq.* We note that hitherto the Development Review has been an internal CEGB document which has not been passed to Government. In explanation, the Board has told us that it has, on request, from time to time provided Government officials with a set of individual sensitivity analyses, especially in respect of particular projects such as Heysham II, which would enable officials to carry out their own combined sensitivity analysis. We do not find the argument convincing, because some of the sensitivities are neither additive nor linear, and a full exploration of sensitivities would require access to the Board's own system planning model. There is a strong obligation on the Board to make clear to Government the measure of the uncertainties which in fact surround its investment decisions.

5.159. The material supplied by the Board to the Select Committee on Energy contains one example of a combined sensitivity test (see paragraph 5.110). We note that there is no discussion of the status of the numbers used (for example whether the CEGB's past experience would lead one to expect that a 50 per cent cost overrun might be the consequence of a three year overrun) such as one might expect in a document prepared for this purpose. The range of outcomes displayed is very limited, and we feel that commentary on the significance of the results may mislead insofar as it invites the Committee to conclude that those displayed are equally likely. Our examination of the CEGB's past experience, and the factors which will bear on future performance, strongly suggest that they are not.

5.160. We conclude that the CEGB's presentation of investment appraisal results both internally and externally falls some way short of the standards we believe to be necessary to achieve a full understanding of the robustness of the basic NEC estimates. As a minimum the Board should develop its approach in the directions we have indicated. Principally this would involve a much more thorough-going investigation for both internal and external audiences of the results of combined sensitivity tests for outcomes which are more likely to occur than the kind of extremes represented by either basic NECs or the nuclear cases shown in Table 5.11.

5.161. We recommend, however, the further step of re-orienting the approach altogether and presenting outcomes associated with the central estimates of all the relevant determining variables. The CEGB has told us it does not favour this approach for the reasons set out in paragraph 5.94.

5.162. In considering the views of the Board, we think the following four points are relevant. First, we believe that the CEGB should make rational estimates of the most likely outcomes for the technical parameters (such as construction costs and plant performance variables) and that if necessary it should expand the information or expertise at its disposal in order to do so. We draw attention to Barnwood's approach to construction cost and time estimation which we believe could be readily developed in the appropriate direction. To do so would require a careful analysis on the one hand of past outcomes and on the other a realistic assessment of the consequence of managerial initiatives designed to improve performance. We are therefore not (see Table 5.13) recommending that 'central' estimates should simply be based on the Board's past experience. We would emphasise that the central forecasts should be based on a realistic assessment of the improvement which management action is likely to achieve, especially in the short and medium term. In suggesting that it would be feasible to develop central case forecasts for use in investment appraisal, we recognise an important but nevertheless quite separate role for targets, which would represent an improvement on the most likely level of performance, in the context of motivating line managers and providing incentives to contractors and their workforces.

5.163. Secondly, there is an obligation on the Board in its dealings with Government to make clear the nature of the uncertainties surrounding its decisions. We believe that this can be most effectively done by concentrating the presentation of investment appraisal results on the most likely outcome with an examination of uncertainties based on the appropriate combined sensitivities, illustrating both favourable and unfavourable outcomes.

5.164. Thirdly, the Board believes it can now justify a programme of investment in nuclear generating capacity on cost-saving grounds regardless of planning margin considerations. In making this case, the Board must compare the NEC of nuclear plant either with the net avoidable cost either of maintaining fossil-fired plant on the system, or, in certain circumstances, with the costs of life extension. The latter estimates are central estimates of the costs involved. We believe that in order to demonstrate a convincing case for cost-saving investment 'in advance of need', the Board must develop equivalent central case estimates of the NEC of new plant.

5.165. Finally, we believe that in the context of internal decision-making a presentation of investment appraisal results which takes as its starting point the central estimate, rather than one which would require a highly favourable and unlikely combination of circumstances, is more likely to avoid the risk of unconscious appraisal optimism. The tendency, even in the 1979–80 Development Review, to describe the basic NECs as 'central' estimates is indicative of a risk which would be avoided if the estimate in question really were 'central' in the normally understood sense.

5.166. There is one further aspect of the CEGB's investment appraisal procedures which deserves attention. If the range of uncertainty attaching to the central estimate of NEC differs significantly between alternative projects, then there may in certain circumstances be a case for choosing a project with a higher central NEC but with a narrower range of uncertainty. We note that a decision based on such factors has been taken in the choice of turbine configuration for the first PWR plant. We welcome this approach and recommend that it be appropriately extended to other areas of the CEGB's appraisal of generating plant investment.

Refurbishment and life extension of generation plant

5.167. We recommend that the Board should develop its work on the analysis and forecasting of lifetime repair and maintenance costs which underpins the estimates of the net avoidable cost of life extension. We also recommend that the Board should take account of the results of work in its appraisal of new investment. If there are differences between, for example, nuclear and coal-fired plant in their potential for life extension, then these should be reflected in investment appraisal. Currently they are not. The Board has also said it does not regard plant refurbishment as in any sense competitive with nuclear investment in any of its current longer term 'scenarios'. It seems to us that there are circumstances in which there could be a choice between refurbishment and nuclear investment: where either the required capacity was less than currently envisaged (because of lower than expected demand growth or a reduction in the planning margin) or the rate of introduction of nuclear plant was higher than currently envisaged. We note that although the Board has told us it believes a 1½ GW per annum nuclear programme to be the highest sustainable up to the mid-1990s given existing economic and social conditions, the 1979–80 Development Review discusses an option for building up nuclear capacity at a higher rate than 1½ GW per annum.

5.168. The CEGB has told us that there may be a case for reconversion to coal-burning of some existing oil-fired plant. We recommend that the economics of reconversion should be assessed as a matter of urgency, especially since the modest programme of investment in coal-fired capacity envisaged by the Board for commissioning in the early 1990s appears to be justified very largely as a replacement for relatively modern oil-fired capacity.

The nuclear programme and the nuclear orders

5.169. In reaching conclusions on the robustness of the case for the nuclear programme and the initial orders for AGR and PWR plant, we should make it clear that our views come directly from our assessment of the economic case presented in the Board's investment appraisals. We would also emphasise for the reasons set out in paragraph 5.129 that our views relate primarily to a programme based on AGR plant although we believe some of the factors which affect that economic case will also apply to a programme based on PWRs.

5.170. For the reasons set out in paragraph 5.123 it is important to distinguish between the case for investing in new plant to maintain the planning margin and the case for investing on grounds of cost reduction. The Board wishes to undertake a programme of investment in nuclear generating capacity considerably greater than would be necessary to maintain the planning margin and believes that this larger programme is justified on grounds of cost reduction.

5.171. On the basis of the evidence from the Board's investment appraisals which we have seen and, in particular, taking account of the combined sensitivity test reported in Table 5.14, we are not convinced that the Board has demonstrated a robust case for a programme of this kind. If some proportion of the orders in the Board's preferred programme is to be justified on the basis of cost reduction, then the Board must demonstrate that there is a strong possibility that the central estimate of NEC of nuclear plant will be less than the expected net annual cost of maintaining or refurbishing coal-fired plant.

5.172. On the choice of plant in a context where the investment is required primarily to maintain or increase generating capacity, so that the relevant choice is between new nuclear and new coal-fired plant, we draw attention to the results of the individual sensitivity tests reported in Tables 5.5, 5.7 and 5.8, to the combined sensitivity tests displayed in the 1979–80 Development Review and in Table 5.14 and finally to the comments from the concluding chapter of the 1979–80 Development Review quoted in paragraph 5.101. We would also draw attention to the sensitivity analyses in Table 5.5 which show that the comparative advantage of nuclear over coal-fired plant is critically dependent on forecasts of the future course of coal prices and availability. We have seen that the Board has recently revised downwards its forecasts of NCB prices, and that its views on NCB output and availability around the turn of the century are substantially out of line with other informed opinion. We have drawn attention in paragraph 5.142 to the contrast between the Board's enterprise in seeking out supplies of uranium and the apparent lack of commitment to the long-term development of alternative sources of coal supplies; and also to the significant difference between the Board's expectations of the growth of world coal trade and those contained in the WOCOL study.

5.173. In paragraphs 5.130 to 5.133 we have discussed the economic case for the Heysham II order. The CEGB has stated clearly there is a strategic case for the order (and for an initial PWR order) which does not depend upon the economic appraisal, but it believes that the investment will be cost saving because its attractiveness is robust to a variety of sensitivities. As we have said in paragraph 5.132, we have not examined the strategic case for the order. However, in view of what we have concluded about the robustness of the economic argument that nuclear power would reduce costs in the context of a long-term programme based on AGRs, we are seriously concerned that the strategic case for the Heysham II order may have been unjustifiably reinforced by the supposed economic merits of the project.

5.174. If the Board's costs are to be minimised, it is important that future projects should be assessed on more reliable economic grounds, so that if projects are put forward on other grounds, the cost will be appreciated.

CHAPTER 6

Operational Planning

Introduction

6.1. The two prime planning functions of the Board are Investment Planning, to provide appropriate capital plant, and Operational Planning, to obtain the most efficient use of the capital and other resources provided. This chapter deals with the Board's operational planning.The changing mix of plant available, as new stations and transmission lines are commissioned and old plant closed, and changing relative fuel prices make it necessary to plan operations for several years ahead.

Objectives

6.2. The planning objective is to meet temporal and geographic demand for electrical energy at a pre-set level of security, and to maintain frequency and voltage within defined limits, at least cost. It is relatively easy to provide sufficient generating capacity but much more difficult to do so at least cost when temporal and geographic demand varies through the day, the week and the year in addition to trends over longer time scales, resulting from changes in economic activity. Figures 6.1 to 6.3 show the daily, weekly and annual demand patterns. In recent years the Board has aimed to contain the increase in cost per unit within the change in the Retail Price Index.

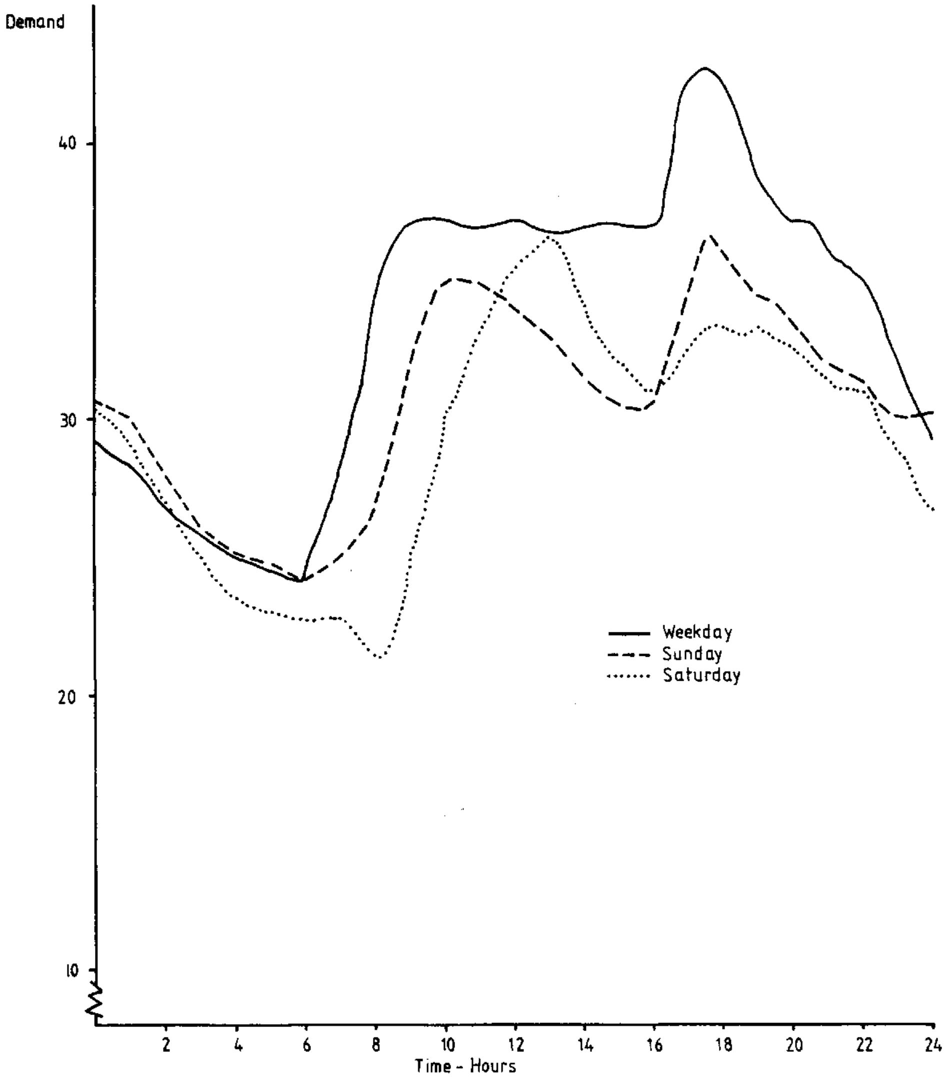
6.3. The national transmission system allows generation and supply points to be geographically separate and therefore assists in smoothing the effects of variations in geographic demand. This provides an opportunity to optimise fuel costs by treating the whole national system of generation and transmission as a single system with all parts optimised simultaneously. However, it also presents the CEGB with a serious organisational problem, namely how to achieve optimality while preserving the autonomy, accountability and motivation of individual managers. The CEGB has attempted to solve this by developing a national simulation model to indicate plant loadings which if approximated in practice would lead to a fuel cost very close to the minimum achievable. The results are used as a guideline around which Regional and Station Managers produce detailed plans including a range of options, for allocating and deploying their resources in an economic manner. Managers are thus given personal responsibility for managing their resources and held accountable for the commitments in their plans.

Management structure for planning

6.4. The management of each Region is organised under a Director General into three Directorates—Resource Planning, Production and Engineering. The functions of Finance, Personnel, Scientific Services and Secretariat are headed by Chief Officers. The Director of Resource Planning is responsible for the integrated planning of all resources on a corporate basis.

FIGURE 6.1

Typical Winter Daily Load Curves

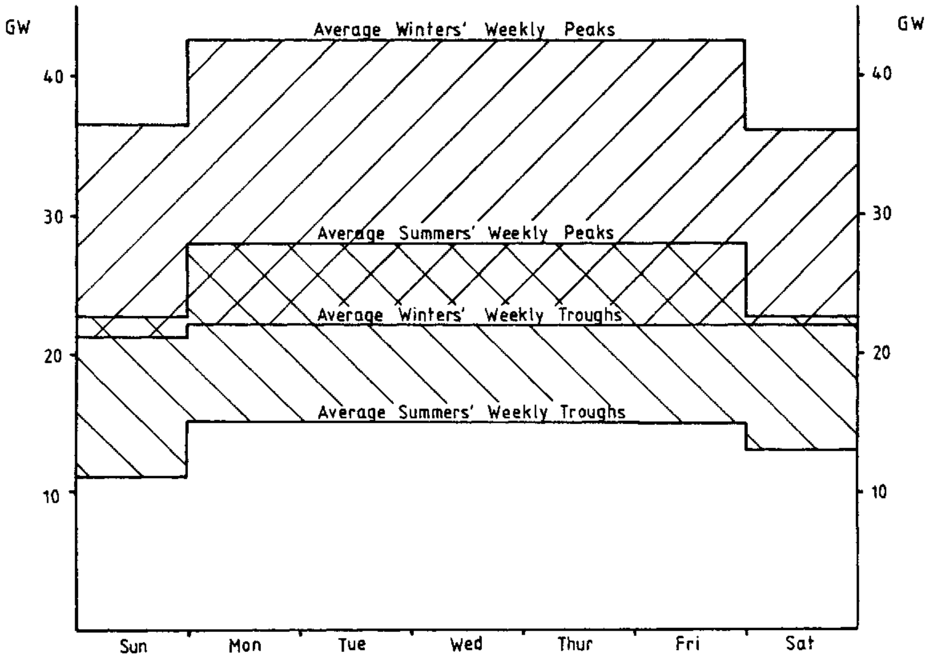


Note: During an average week the daily demand profiles do not vary significantly between Monday and Friday.

Source: CEGB

FIGURE 6.2

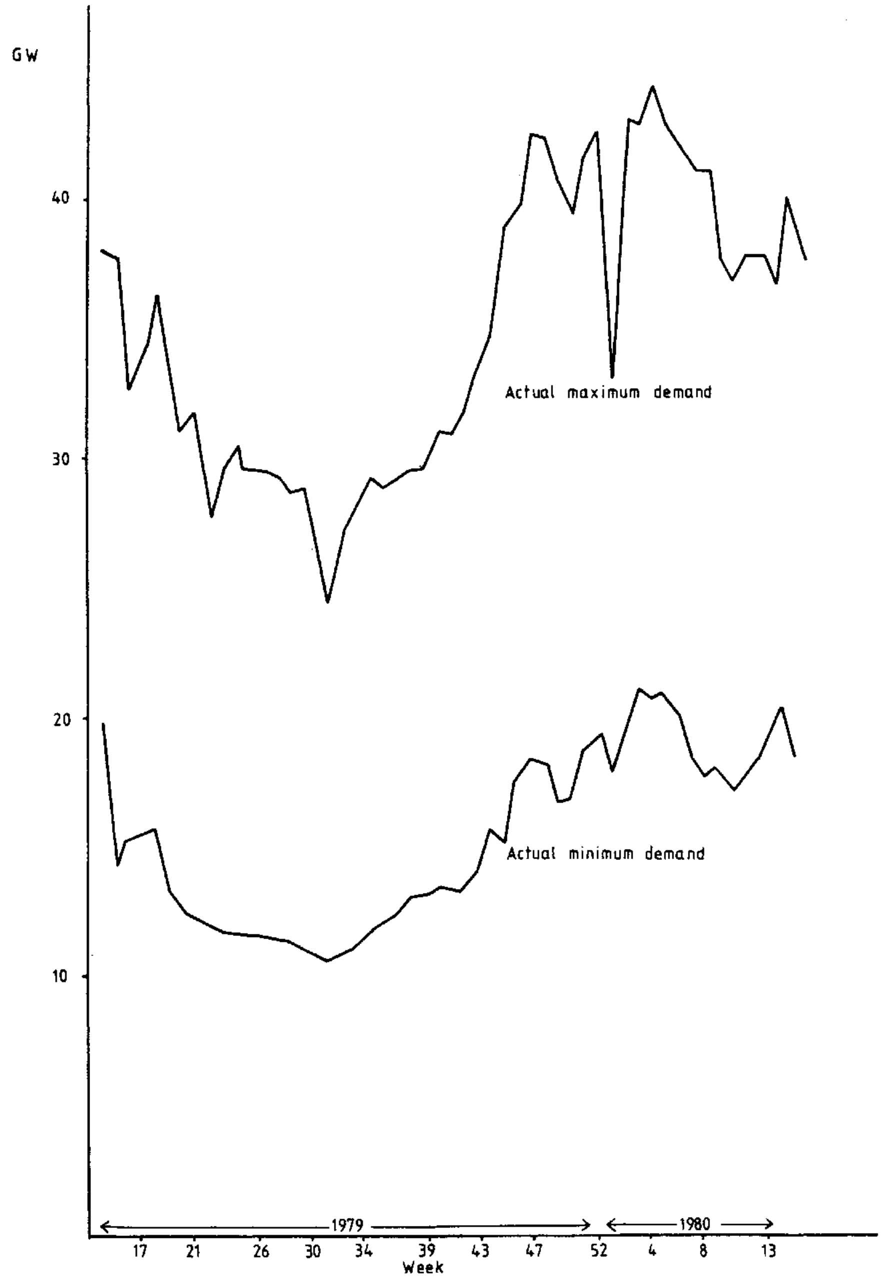
Load Variations Across Summer/Winter Week



Source: CEGB

FIGURE 6.3

Load Variations Across a Typical Year
Maximum and Minimum Weekly Demand 1979–1980



Source: CEGB

6.5. This structure is not reflected either at station level or at Headquarters. At neither is there an equivalent manager responsible for the integrated planning of all resources. At Headquarters there are Functional Directors for Computing, Personnel, Finance, Health and Safety, Information, Operations and Planning. Each Director is responsible for planning within his functions. In particular the Director of Operations plans the operation of the system over the short-to medium-term (up to five years) and the Director of Planning plans the development of the system and the associated capital investment over the longer term (four to eight years) and examines the longer-term system needs up to 20 or 30 years ahead. A branch of the Planning Directorate is responsible for co-ordinating the functional plans into a corporate view. This organisation is not well developed and the Board has indicated that it is reviewing the corporate planning function.[1]

6.6. At power station level the structure varies. Typically under the Station Manager the organisation is functional, with an Operations Superintendent, a Maintenance Superintendent or Heads of Maintenance Departments for mechanical, electrical and instrumentation, a Development Engineer who looks after long-term engineering projects and a Short-Term Planning who plans the annual overhaul. In addition there is a Station Chemist, and an Administration Officer responsible for finance and administration.

6.7. Currently the Board is undertaking a joint review with the EPEA on the restructuring of the organisation at large power stations to reflect the Regional structure. If this were implemented then the Station Manager would be assisted by a Production Manager, an Engineering Manager and a Resource Planning Manager, who would be responsible for the integrated planning of all station resources. This structure has already been implemented at senior management level in some power stations.

6.8. In the rest of this chapter we shall first discuss the method of simulating the national generating and transmission system for energy studies, then the five year planning procedure and its performance, and finally the short-term day-to-day planning of National Grid Control and its performance.

National System Simulation

Introduction

6.9. The Board's main aid to planning and minimisation of the cost of meeting demand for electrical energy is a suite of computer models that simulate the national system of fuel distribution, generation and to a lesser extent transmission.

Evolution

6.10. The present complex simulation procedure has evolved since the 1930s in three phases. Originally, before the linked transmission system of the supergrid, power stations were loaded to meet demand in an order of merit based

[1] The CEGB announced on 8 January 1981 that it had decided to set up a new Headquarters department which would be mainly concerned with both corporate planning and strategy.

on average annual cost of production. Later the introduction of the supergrid transmission system expanded the range of options, and generating units were loaded in an order of merit based on the unit marginal cost of production reflecting annual delivered fuel costs. The industry was basically a single fuel system and in the absence of inflation and changing coalfield price differentials the merit order once determined remained stable over long periods.

6.11. Two events initiated the third phase of computer simulation. First, the industry became a multi-fuel user, of nuclear fuel, coal, gas and oil, giving rise to an allocation problem when one or other fuels were under supply constraints. Secondly, there were rapid changes in the relative prices of fuel. These factors gave rise to a range of options for the purchase and distribution of fuel and the allocation of load to generating capacity, exhibiting a range of costs. Moreover, once a minimum cost configuration had been computed it remained stable for a relatively short period only.

6.12. In the 1970s the need became clear for a national simulation of energy use which could be revised frequently. The CEGB developed a suite of computer models which were brought into use in 1974.

6.13. The simulation procedure calculates the 'system marginal cost' (SMC) for given demands, fuel costs and generation availability and selects the minimum fuel cost allocation. (By 'system marginal cost' is meant the cost of providing an additional unit of energy.) The basic set of programs is called the SYMAN suite (System Marginal Costing), and is used for short-term detailed studies; two simplified derivations, STEAM (Strategic Energy Appraisal Model) and SIMOP (Simultaneous Optimisation) are used for sensitivity and longer-term studies.

The merit order principle

6.14. The basic principle which the CEGB uses to minimise the fuel cost of electrical energy is to rank its power stations, or more precisely, each generating set, in a 'merit order' of cost of production, and to follow incremental or decremental changes in demand by loading or off-loading generating sets sequentially in the order of merit.

6.15. The effectiveness of the merit order depends on the appropriateness of the cost definition. Merit order costs could be based upon average total cost, average variable cost, or marginal costs. The CEGB uses a marginal costing criterion, the marginal cost of supply for a given generating set being defined thus:

SYSTEM MARGINAL COST PER UNIT (pence/kilowatt hour)

= HEAT RATE FOR SET (kilojoules/kilowatt hour)

× INCLUSIVE SYSTEM MARGINAL COST OF DELIVERED HEAT (pence/kilojoule)

The heat rate is determined for each set by a heat test, based on a total heat balance, and adjusted for operating conditions, circulating water temperature, and fuel quality. The fuel calorific value is currently determined gross for that set but from April 1981 will be determined as net invoiced calorific value.[1] The use of 'system' in the definition means the total process of fuel supply, generation and transmission on a national scale.

6.16. The inclusive system marginal cost of heat delivered includes:

(*a*) the incremental cost to the total system of delivering an additional unit of heat to the set; and

(*b*) the incremental cost in fuel and ash handling.

The former is derived from price of fuel at source and transport costs, and the latter includes repair and maintenance costs, salaries and wages on handling equipment offset by income from sales of ash.

6.17. Figure 6.4 shows the shape of the national merit order load curve and the position on it of power stations in the SE and SW Regions. Figure 6.5 shows diagrammatically how they would be loaded in merit order to follow the daily demand pattern.

The validity of using system marginal cost of heat

6.18. Over the short- to medium-term, up to about two years, when the configurations of generating plant and fuel sources are fixed, costs are influenced by load-dependent variables only and load allocations will leave fixed costs of plant and labour unchanged unless operating regimes are varied. Within this time span it is appropriate to use some form of variable costing related to the load-dependent variables rather than total costing. The variables to be included may depend on the time horizons considered. The maintenance costs of boilers and generating sets may be load-dependent for different operating regimes over the long-term, whereas over the very short-term (one or two days), the delivered cost of heat may not be an appropriate variable, because pre-programmed fuel deliveries may be difficult to alter and transport and differential fuel cost are effectively fixed. In the latter case the only effective operating variable is thermal efficiency (TE), and the merit order reduces to a ranking by thermal efficiency which is equivalent to a minimum fuel burn criterion.

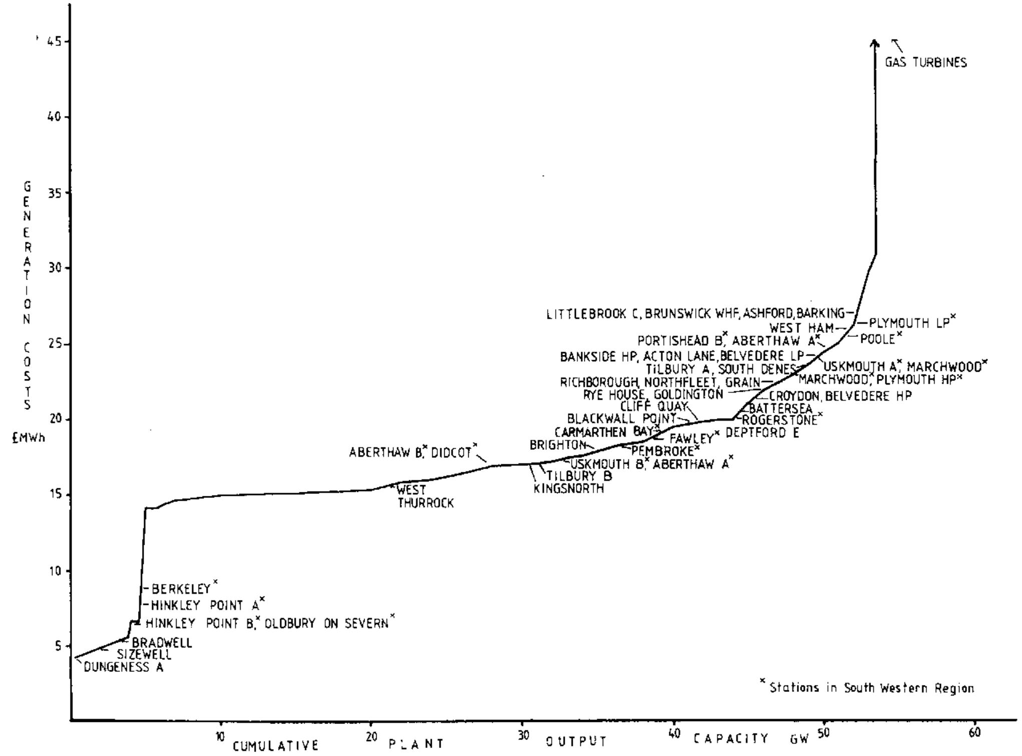
6.19. All discrete sources of fuel have limited capacity and, under capacity constraints, a change in the volume of fuel delivered to one location will result in consequential changes in the patterns of supply, and costs, elsewhere in the system. In addition, as the volume of fuel burnt at one location increases, the marginal cost of fuel at that location will increase as local or cheap supplies are exhausted. Thus the marginal cost of fuel will in general be higher than the average cost of all fuel burnt at the locations. For these reasons we agree with the CEGB that it is appropriate to use system marginal costs.

6.20. System marginal costing is used as the basis of cost minimisation in the SYMAN simulation suite. The costs of long-term variables such as the maintenance costs resulting from the varying load patterns of different operating regimes are considered outside the SYMAN suite. The merit order

[1] The change in definition provides for variation in the efficiency of different burners in converting fuel into primary heat.

FIGURE 6.4

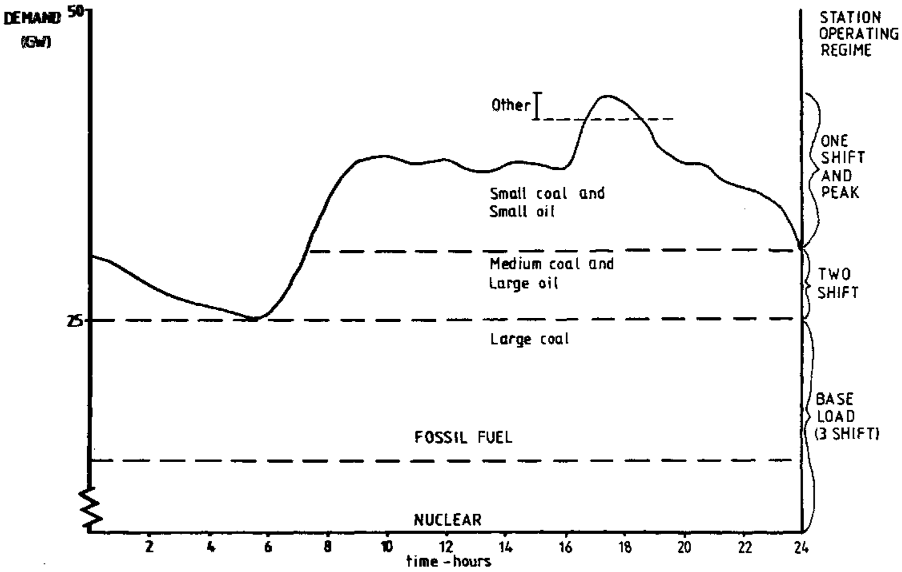
National Merit Order July 1980 Showing Stations from South Eastern and South Western Regions



Source: CEGB.

FIGURE 6.5

Merit Order Loading Sequence to Follow Daily Demand



Source: CEGB.

derived from system marginal costing is used at Grid Control for short-term planning. This would certainly be appropriate if the actual operating conditions were very close to those which were assumed for the system simulation studies. It is not at all clear that minimum cost would be obtained by the use of the system marginal cost merit order in operating conditions very different from those assumed to obtain the merit order. The Board attempts to reduce any cost penalty by making minor adjustments to the merit order daily between full scale simulation runs; the adjustments are calculated by an approximate method taking account of actual heat rates and fuel costs. If the assumed conditions and actual operating conditions are identical then the system marginal cost criterion will always give a cost at least as close to the minimum as the thermal efficiency criterion and in most cases a lower cost. The Board has told us that if operating conditions were to vary significantly from those assumed then the merit order would be re-computed using SYMAN.

The computer simulation model for system marginal costing (SYMAN)

6.21. The SYMAN suite is designed to determine an optimal fuel allocation and the merit order for loading plant to achieve minimum cost of production. It comprises three modules:

(i) Merit Order Calculations (MOCAL);

(ii) National Economic Load Scheduling (NELS); and

(iii) Coal Oil Fuel Allocation (COFAL).

6.22. MOCAL. This module stores heat rate data for each generating set and combines this with system marginal fuel cost to produce the merit order for scheduling and loading plant. It produces two merit order costs for each set.

TABLE A costs: which represent the full load cost including the no load cost. Table A is used to schedule plant on and off the grid.

TABLE B costs: which represent incremental load cost once the set has been connected to the grid. Table B is used for incremental loading of plant to follow small changes of demand.

6.23. NELS. This module simulates the scheduling of generation sets between the peaks of a daily demand curve. Plant is loaded to meet demand in merit order until any limit is reached on the transmission system which restricts geographic transfer of power. Plant is then loaded out of merit order to maintain security. Total generation is adjusted to satisfy demand and provide spinning reserve. The process is repeated for each half-hour period following the demand, scheduling being consistent with time-dependent plant constraints. The daily simulation is repeated to cover the period of the energy study. The final output is the on-load heat required at each station in the system over the period. The results are used as input data to COFAL.

6.24. COFAL. This module is formulated as a linear program to provide an optimal allocation of each type of fuel from a given source to a given station by a specified transport mode, so as to satisfy on-load and off-load heat requirement at each station at minimal cost over the period. The minimisation includes both source cost and distribution cost. The system marginal delivered heat cost is calculated for each station.

6.25. The NELS and COFAL modules are used in an iterative loop, the output of COFAL being fed back into NELS to revise the merit order. The cost estimates converge towards an optimum after a number of iterations. The process is usually stopped after about nine iterations or 50 hours of computing time. After convergence MOCAL is activated to print out the system marginal cost merit order.

6.26. At convergence the cost uncertainty, ie the cost change from iteration to iteration, is about £50,000 in a total cost of £3,300 million or about 0·002 p/GJ on a total of 140 p/GJ.

6.27. The output available from the SYMAN simulation is listed below:

(*a*) merit order Tables A and B;

(*b*) generation loading details;

(*c*) station unit allocations;

(*d*) fuel source requirements and costs;

(*e*) transport utilisation;

(*f*) total inclusive fuel cost; and

(*g*) marginal utilities of scarce fuels, ie the value the Board would obtain if a further unit of the fuel were made available.

6.28. Appendix 14 sets out in more detail the data required and the constraints formulated within the SYMAN suite.

SIMULATION TIME HORIZONS

6.29. The simulation programs are used for simulating system costs up to a number of time horizons. The results are used as guidelines for detailed planning within the devolved management responsibility.

THE FIVE YEAR TIME HORIZON

6.30. Regional and Station Managers are responsible for allocating resources to achieve the planned station availability over the next five years, to support the estimated forward loads and to achieve the highest thermal efficiency that can be commercially justified.

6.31. The simulation runs are used to test different loading strategies and select the best operating regimes for the years ahead. For example, when demand falls below available base load capacity, should the large sets be partly loaded all the time or should some be 'two shifted'[1]. In a recent study the effect of two-shifting the large 500/660 MW units was investigated. A mixture of overnight shutdowns of some 500/660 MW sets, supplemented by similar shutdowns at weekends and holidays, combined with part-loading of other large sets, would result in a saving of between £30–£55 million in the years 1981–82 to 1985–86, compared with the original part loading mode of operating. A further potential saving of £10–£15 million by additional two-shift operating was identified.

6.32. The original simulation models did not take transmission costs into account, ie the variable cost due to distance-related losses. Recently a study to assess optimisation of transmission has been completed. A potential saving of about £0·5 million a year was identified. The result of the study has been included in the simulation in the form of adjusted heat rates. However, its effectiveness depends upon the pattern of transmission remaining steady. There is no reason in principle why transmission optimisation should not be included as a dynamic variable in the model.

6.33. The simulation runs are also used to assess the options for station closure and to determine the consequences of delays in commissioning new plant.

6.34. *The two year time horizon.* Studies for two years ahead expand the detail and are used as the basis for budgeting in the first year of the five year period, and for provisional budgets in the second.

6.35. *The six month time horizon.* A detailed SYMAN run is produced twice a year for a six month period to act as a guide for Regional management in planning the summer and winter fuel procurement programme. The details

[1] Power stations are normally organised to provide three shifts to cover the 24 hours; a station is two shifted when it generates power for only two of the three shifts.

of the method of optimising the fuel deliveries by the Regions over each of the six month periods, using the national simulation guidelines to ensure an approximate global optimisation, are discussed in Chapter 7.

SENSITIVITY STUDIES

6.36. Studies are made to determine how robust the cost of the solution obtained from the six month study is to changes in input assumptions, availability of plant, relative fuel cost, fuel availability and demand.

6.37. The merit order is particularly sensitive to restrictions on fuel availability. Currently however there are few such restrictions, and therefore the present solutions are robust to quite significant changes; the cost penalty for not reoptimising on changed fuel conditions but using the existing merit order is relatively very small.

The Five-Year Planning Procedure

6.38. As indicated previously each location (power stations or transmission district) produces annually an operational plan for the next five years, the first of which is converted to the budget for the next financial year. Planning is on a rolling basis; the remaining four years of the previous plan are reviewed and an additional plan year added. During the compilation of the plan there are a number of iterations between the station and Region, and between Region and Headquarters, to ensure that the plan is both adequate and feasible. The plans are work-based in that they are built up from specific and quantified work projects at power stations level.

The planning cycle

6.39. The planning cycle, although resulting in an annual product, takes approximately 18 months to complete. The detail varies between Regions but typically comprises two phases:

(i) *A review phase* in which the historic out-turn is assessed and viewed in the light of an outline plan at station level. This is assisted by station and Regional status reports and engineering reviews, which comment on the state of all plant and the progress of engineering projects. The iteration during this phase helps to set targets which are feasible and prepare guidance for the more formal second phase.

(ii) *A formal planning phase* in which each location prepares detailed work-based planning proposals for the next five years. The proposals set out the resources required to achieve agreed targets and support the loads in each period estimated by the national system energy studies.

6.40. The review process allows the Regional Director General, assisted by the Director of Resource Planning, to prepare draft planning guidance to locations in advance of the formal planning guidance issued by the Executive. Indeed, the review process allows Regional management to advise the Executive on the possible future performance of plant and the range of planning options available and to provide a firm quantitative background against which to prepare formal planning guidance.

6.41. The main steps and approximate timetable are set out below.

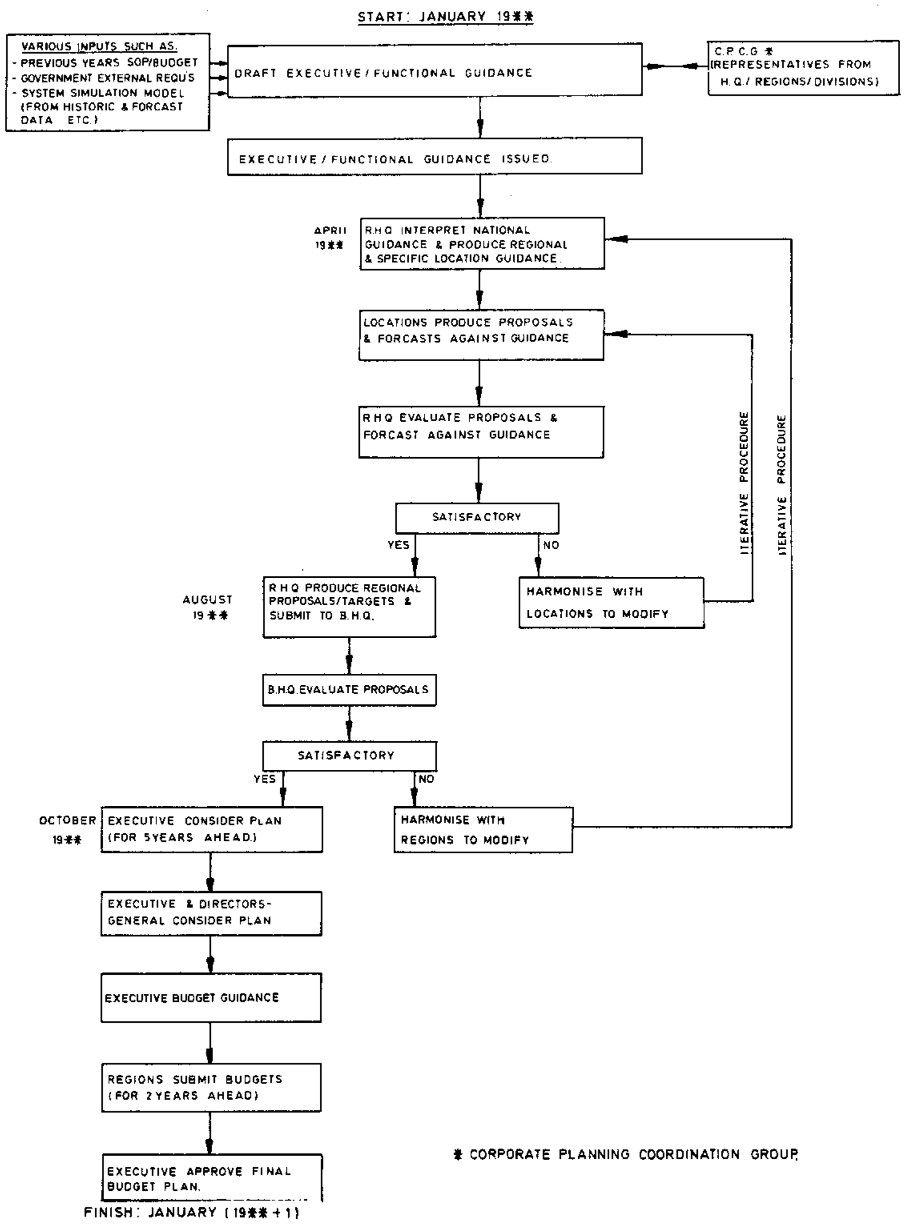
1.	Region and location managers prepare and assess Out-turn Report, Status Report, and Engineering Review. Provisional targets are discussed.	Oct of previous year to Jan of planning year
2.	Director of Resource Planning at Region issues draft location guidance setting out targets and planning assumptions for next five years.	Jan–March
3.	Regional Directors General and Headquarters Chief Officers prepare draft Executive and functional guidance.	Jan–Feb
4.	Location Managers prepare draft location plans setting out resource requirements and options for achieving the targets.	Feb–June
5.	The Executive issues formal planning guidance to Regions.	March–April
6.	The Executive and Regions discuss the Executive guidance and Regions receive additional guidance on particular topics.	April–June
7.	Regions issue modification to draft location Guidance in the light of formal Executive Guidance.	April–May
8.	Modification of location plans and submission to the Director of Resource Planning at Region.	May–June
9.	Harmonisation and aggregation of location and department plans into a Regional Outline plan.	July–Aug
10.	Chief Officers and Corporate Planning branch at Headquarters summarise the Regional Outline plans and prepare the national September Outline plan.	September
11.	Adoption by the Executive of particular options set out in Outline Plan and the issue of budget guidance.	October
12.	Production of Annual Budget by location.	Nov–Dec
13.	Preparation of National Budget from Regions and location budget. Budget approved by the Executive.	Jan–March following year

Figure 6.6 sets out the planning procedure in schematic form. This illustrates the formal sequence but does not show the anticipatory nature of some of the steps.

6.42. This is an extremely tight timescale and provides little slack for replanning if the draft plans are not acceptable to the Executive. For this reason the Board introduced the concept of including a range of options in the plans. This has two advantages. First, the Executive can select the most appropriate option and the possibility of rejection is much reduced. Secondly, if during implementation the planning environment changes, then the locations can respond rapidly by adopting one of the range of options, which have already been well developed.

FIGURE 6.6

The Board's Target Setting Procedure



Source: CEGB

Structure of Regional guidance to locations

6.43. The Regional guidance issued to each station location sets out of the general Regional targets, assumptions and the view of the next five years, together with specific guidance to the location.

6.44. The content and form of location guidance vary from one Region to another but typically a location's guidance has three parts:

(*a*) Targets, achievements and budget summary extracted from the previous five year plan. The opportunity costs for increased availability and thermal efficiency are set out as a guide to making commercial value judgments.

(*b*) The forward estimates of relevant parameters derived from the Energy Study National Simulation for the five years ahead:

— Expected estimate of annual loading, ie the number of units that the station is expected to produce. This is in the form of a central estimate together with a high and low confidence interval.

— Expected fuel parameters such as the total fuel burn.

— The expected operating regime for the location, ie five day or seven day working, three or two shift working.

(*c*) Targets for some or all of the following:

— availability;

— gas turbine start reliability;

— thermal efficiency;

— STEP factor (relative efficiency);[1]

— staff levels;

— revenue and capital budget.

Setting targets

6.45. The method of setting targets differs between Regions. In most Regions the targets are set in the formal guidance before the plans are produced. In one Region the guidance does not set formal targets, but targets are adopted after the draft plans are introduced. In either case targets are set after a consultative process between the Station Manager, the Director of Production, and Director of Resource Planning. The actual target will be set with regard to:

— historical performance and trend;

— relative performance between stations;

— projects under way;

— a measure of improvement.

All parties agree upon the target and its feasibility.

[1] STEP (STANDARD THERMAL EFFICIENCY PERFORMANCE) FACTOR: This is the ratio of the thermal efficiency actually achieved to the maximum achievable adjusted for factors outside the station's control such as loading pattern and operating regime.

6.46. The parameters for which targets are set vary between locations and depend on the operating regime and the position of the station in the merit order.

— *High merit base load stations*, ie the nuclear and large coal-fired stations, have targets set for availability as a first priority; other parameters such as revenue expenditure are not targeted, because in most circumstances it will be worthwhile to provide the resources needed to maintain availability.

— *Mid merit*, ie large oil and medium coal-fired stations, would typically have targets set for availability and thermal efficiency. Additional resource inputs to increase the merit order rating may be justified giving greater value to increased availability.

— *Low merit*, ie the small coal and oil-fired stations, may have targets for manpower, revenue and capital expenditure. The engineering parameters such as availability and thermal efficiency are optimised within financial constraints. These stations are less important and present more scope for cost reduction.

This strategy diverts funds from the low merit to the high merit stations. This form of guidance is not universally adopted in the Regions, but as financial constraints become tighter the trend is in this direction either formally through guidance or informally.

Executive guidance

6.47. With a knowledge of the station Out-turn Report, the Status Report and Engineering Review, the Regional management can form a view of the probable level of future performance in the Region together with a view of feasible policy options with respect to operating regimes, closures and commissioning of new plant. The Executive guidance is first prepared in a Regional context between the Regional Directors and Chief Officers. In some Regions there is a Regional Corporate Planning Co-ordinating Committee for this purpose.

6.48. The Regional Directors of Resource Planning and the Chief Officers at the CEGB Headquarters exchange their views formally at the Corporate Planning Co-ordinating Group. The Chief Officers with the advice of the Regions then prepare separate papers for each function—Planning, Operations, Manpower and Computing, together with a draft Executive Guidance.

Executive Guidance: Summarises the Board's longer term objectives and sets out the planning context in terms of production levels and costs and identifies any fuel or demand constraints. The interaction of these factors with pricing and marketing strategies is discussed.

Functional Guidance: Sets out for each function the background planning data for use in the preparation of plans, and guidance on specific items.

6.49. These papers provide the Executive with advice on planning assumptions such as inflation rate and demand forecasts and draw attention to the need to establish possible policy options worth evaluating in the subsequent planning stage.

6.50. The Executive reviews the proposals in each function, approves, rejects or modifies particular options and may also set particular national targets. Recently some very rigorous targets have been set:

— an increase of 4 per cent in plant availability;

— containment of costs within the national rate of inflation;

— significant reductions in staff numbers.

6.51. The approved functional papers are then collated and issued as Executive Guidance to the Regions. In the light of this the draft station and Regional plans may need to be modified. Finally each Region submits its plans which are collated to produce a national outline plan for consideration by the Executive.

6.52. After approval of its plan each Region makes a commitment to provide an agreed generating capability for system operation on a 50/50 probability basis ie that a Region expects to exceed its commitment as often as to fall below it.

Planning at station level

6.53. Planning at station level starts with the objective set out in the Executive Guidance and the Station Engineering Review. The Engineering Review is a station report on the state of all plant and major works outstanding. A list of work necessary to achieve the targets of the guidance is constructed and the various options are assessed against two criteria, return on capital and time to pay back.

6.54. The selection of work to be undertaken always depends on commercial judgment as to whether the project benefits outweigh the cost, and the net benefits which might be derived from the use of the resources elsewhere in the system. The technical base of the industry is well understood and a quantitative assessment can be made both of costs and of benefits expected, the latter in terms of predicted improvements in station parameters.

6.55. *Planning availability*. Availability is a function of the length of planned overhaul for statutory inspection, outstanding repairs and routine and preventive maintenance, and unplanned outages or output restrictions resulting from plant failure. Planned outage time can be varied by delaying or bringing forward work. Unplanned outages can be reduced by increased preventive maintenance or re-design. Information about the historical failure rates of plant is recorded and helps in the development of maintenance options. The relationship between maintenance and availability is discussed in detail in Chapter 8. Appendix 15 sets out in more detail how availability is predicted.

6.56. *Planning thermal efficiency*. The factors which would contribute to increased thermal efficiency are determined by technical analysis of the heat balance and have been catalogued for each station. The incremental changes to station generating costs associated with changes in each factor are also known. It is relatively easy to assess the costs and benefits for projects designed to improve thermal efficiency. They can be set out in cost options against target thermal efficiency. Appendix 15 (Table 1) sets out the thermal efficiency parameters for Fawley power station.

6.57. *Planning cost reductions.* Cost reduction at power stations can be achieved principally by two methods, first by improvement in 'housekeeping' and attention to best operating practice, and secondly by capital works designed to improve operating characteristics. The major areas for cost reduction are:

(*a*) *Generating efficiency*

(i) By increasing availability and reducing the number of starts, thermal efficiency is increased.

(ii) Optimising plant running conditions.

(iii) Minimising the use of works power, especially by increasing availability of steam-driven feed pumps.

(*b*) *Fuel costs*

(i) On coal-fired stations by minimising the use of oil burn. Oil is used to stabilise the flame at low loads; its use can be reduced by improved design of the burner injector and by improved flame monitoring, and by improved coal milling.

(ii) By improved fuel management at nuclear stations. Wylfa has improved its fuel utilisation by about 20 per cent.

(iii) By using lower grade fuels (which however may raise costs in other sectors).

(*c*) *Works costs*

(i) By programming and control of maintenance expenditure.

(ii) By control of engineering spares stocks. This is discussed in detail in Chapter 9.

(*d*) *System costs*

By monitoring station flexibility of regime. Any inflexibility on load, or loading/off-loading lead times, may result in Area Grid Control being unable to use the station in its most economic mode.

(*e*) *Dust disposal*

(i) By optimising the utilisation of transport, eg by not part-loading trains.

(ii) By marketing and sale of ash.

(*f*) *Manpower*

(i) Management Services Review of productivity procedures.

(ii) Matching manpower to operating regime.

(iii) Optimising the use of contract labour for planned overhaul.

6.58. Judging the scope and sequence of work projects to be built into the plan and in particular into the next annual budget is the responsibility of the Station Manager. He is assisted in this task in a variety of ways in different Regions. They may include:

(*a*) The Station Manager taking direct advice from the Group Manager and department heads at stations.

(*b*) Commercial Development Panel, which consists of Station and Regional representatives. The panel advises about the assessment of costs and benefits of projects and also monitors their progress.

(*c*) A combination of a Budget Control Panel and an Engineering Liaison Committee, the Budget Control Panel advising about the economic viability of projects and the Engineering Liaison Committee assessing the resources needed for capital projects.

6.59. Each station draws up a list of engineering jobs necessary in the next five years to achieve the targets for engineering parameters and operating regime. From this list, and the estimated loadings from the SYMAN runs, the following can be derived:

— expenditure on fuel;

— other revenue expenditure;

— capital expenditure;

— manpower requirements;

and set out in terms of a five year plan. The plan usually contains a number of options with different resource requirements which relate to the 'pay-off' between long- and short-term benefits. When budgetary approval has been obtained the first year of the plan is converted into an operating budget with estimated expenditure set out monthly under revenue and capital cost categories.

Monitoring performance

6.60. Station performance is monitored against location plans daily, weekly, monthly and annually. The parameters monitored by Regions include:

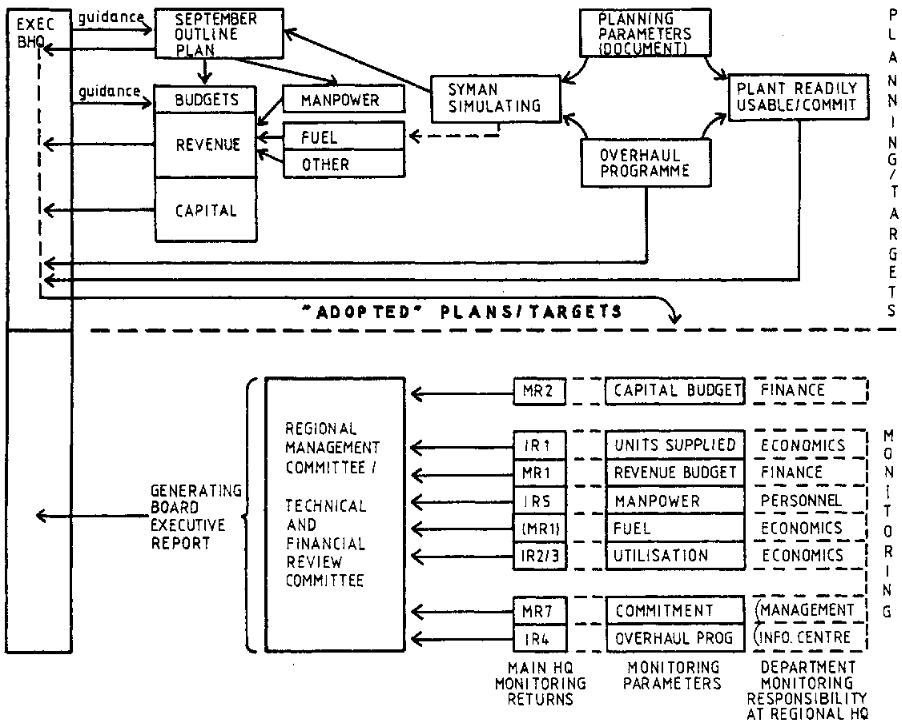
(*a*) Engineering performance:	— availability; — thermal efficiency; — STEP factor; — fuel parameters; — generated output.
(*b*) Financial performance:	— revenue expenditure; — capital expenditure.
(*c*) Manpower performance:	— staff in post; — productivity; — overtime.
(*d*) Large projects:	— progress.

Figure 6.7 shows the relationship between the September Outline Plan (SOP), the budget and the main monitoring interfaces between the Region and Board HQ.

Effectiveness of the planning procedure in terms of performance

6.61. *Response to change.* During our investigations we observed many examples of the ability of the planning process to accommodate rapid change. This results from three characteristics. First, the plans include optional courses

FIGURE 6.7



"COST & PERFORMANCE SYSTEM"-MAJOR BHQ/REGIONAL MONITORING INTERFACES

Source: CEGB

of action. Secondly, the plans are based on identified tasks and contain feasible targets. Thirdly, planning is a continuing process with well developed procedures. Examples of the speed of response are:

The fire at Tilbury B: In 1977 the boiler house, turbine floor and control room of Tilbury B were completely gutted by a cable fire. Within an hour the national plans had been revised to take into account the non-availability of Tilbury for generation, and an emergency plan was outlined within a week. The refurbishment plan drew on the workshop resources of other stations. In four months the switch gear and the first set were recommissioned and all four sets were operational within 14 months.

Spare rotor for Ratcliffe: On 21 July 1980 the generator rotor on one unit at Ratcliffe became defective. There were no spare rotors available and it was decided to shut down one of the mid merit oil-fired units at Pembroke power station, which used the same rotor design, and install the rotor in the Ratcliffe unit. The unit was re-commissioned on 21 August. The Pembroke unit was re-commissioned on 9 December.

Budget reduction at Fawley: In response to a revised demand estimate and the consequential need to bring expenditure into line, the budget for the Fawley plan was reduced, as a result of replacing and deferring projects, by £400,000 out of a total of £7 million. This was achieved during the first half of the budgetary year. The consequences in terms of station performance were determined and fed into the national plan.

6.62. *Achievement of objectives.* In recent years the CEGB has set itself the long-term objective of containing the rate of increase of its production costs within the rate of increase in the Retail Price Index. The success of its planning procedures should be judged in this context.

6.63. The decade 1970–1980 spans two distinct planning environments, the 'cheap oil' regime prior to 1974 and the 'dear oil' regime subsequently.

6.64. We have attempted, in terms of the Board's own objective, to judge its success by comparing the probable real increase in unit cost, had it continued with the operational policy current in 1971 with the actual achieved real change over the decade. We have chosen 1971 as a base year because by then most of the consequences of the Board's strategy for the cheap oil period were apparent.

6.65. As a basis for the comparison we have estimated the probable unit cost of a hands-off policy, that is assuming that no corrective action was taken for changes in relative fuel prices nor advantage taken of changed demand to increase productivity. The four main operational assumptions were:

(*a*) that there was a constant fuel mix usage for the units actually supplied;

(*b*) that manpower input per unit was constant over the decade;

(*c*) that thermal efficiency remained constant; and

(*d*) that capital utilisation (ie availability) remained constant.

The national trends for many cost components of the CEGB's revenue expenditure have been worse than the RPI. In the comparison base we have assumed that the Board's costs for these components could have followed the national trend.

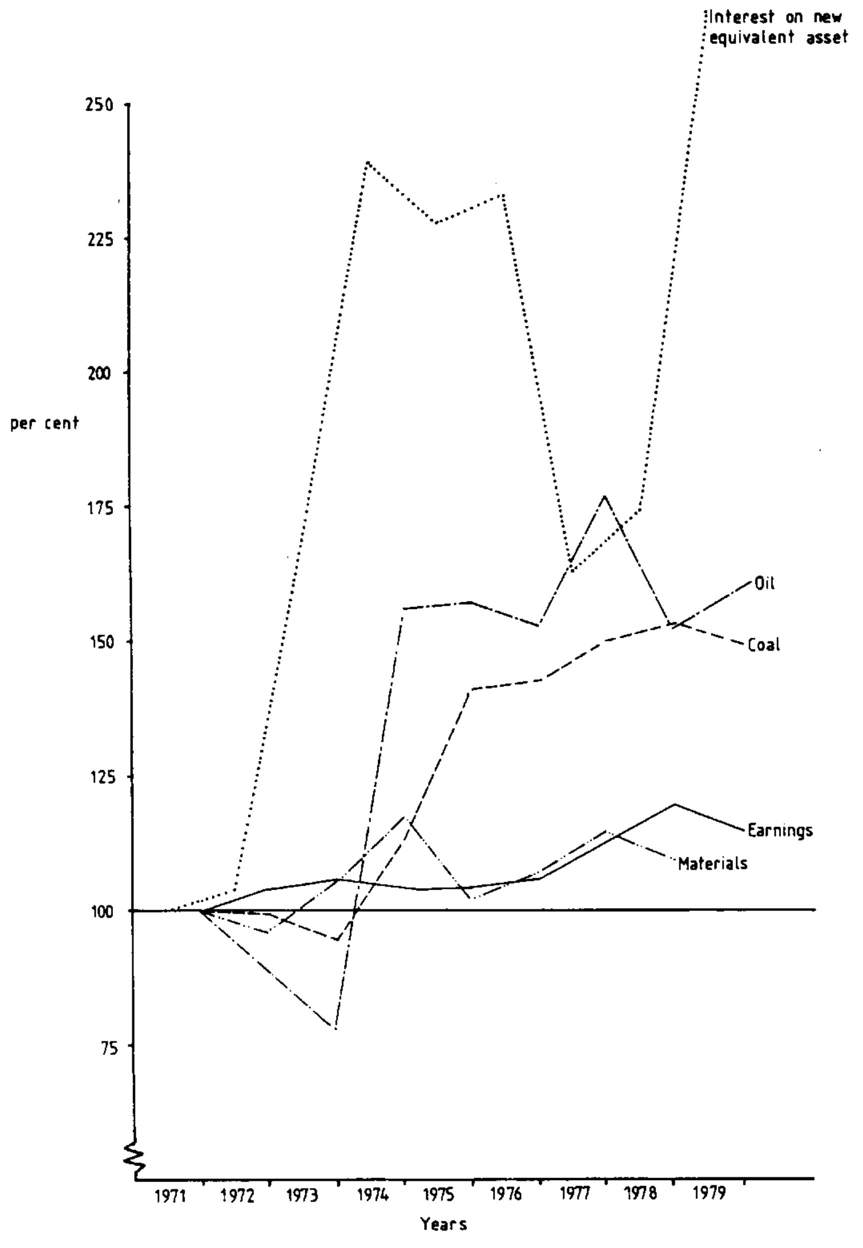
6.66. Figure 6.8 shows the national cost trends, adjusted for RPI, of the main elements of the Board's revenue expenditure. This represents the changing external environment against which the Board had to prepare its plans. The main components are fuel, salaries and wages, materials, interest and depreciation and Figure 6.8 shows the real change in these costs if they had followed the national indices set out below:

Coal	— The index of 'Wholesale Price for all UK Industry'
Oil	— The index of 'Wholesale Price for all UK Industry'
Wages	— The index of 'Average UK Earnings'
Materials	— The index of 'Materials in Electrical Engineering Industry'
Interest	— We have assumed that capital costs have followed the index of costs for 'Public Construction Industry' and that interest was at Treasury lending rate.

The cost trends for gas and nuclear fuel are not shown on the figure; however for the purpose of the base comparisons we have assumed that the unit costs were those actually incurred.

FIGURE 6.8

National Cost Trends of Factors Significant to the Revenue Account of CEGB 1971–79 all Deflated by RAI



Sources: Digest of UK Energy Statistics 1980
Dept of Employment Gazette
Financial Trends

6.67. The estimated trend of unit costs, adjusted for RPI, resulting from a hands off policy since 1971 is shown in Figure 6.9 as in case 'A' and could be considered as a probable worst cost. This is compared with the CEGB's actual trend in unit cost, also adjusted for RPI, as case 'D'. The difference between 'A' and 'D' represents an improvement with respect to external trends, which has been achieved by:

(*a*) an increase in thermal efficiency;

(*b*) a change of fuel mix; and

(*c*) an increase in manpower productivity.

The relative gains are shown in the figure by considering two intermediate cases,

Case 'B' as for Case 'A' but with the effect of increased thermal efficiency included.

Case 'C' as for Case 'B' but with the Board's actual fuel mix substituted for the 1971 mix.

The difference between case 'C' and case 'D' represents the improvement obtained by increased productivity.

6.68. The CEGB has also influenced the unit cost trend by a change in its investment policy since about 1968. Since that time the real investment per unit supplied has been decreasing, part of which may have resulted from improved capital utilisation. The result has been that the interest component of unit cost has been reduced in real terms. It is difficult to estimate the consequence of this change because of the problems of revaluation of assets.

6.69. These estimates are not intended to be definitive but merely to illustrate the order of the CEGB's performance relative to the changed planning environment.

6.70. The Board's objective presents management with a very difficult task. Since 1974 all major elements of input costs have risen faster than the RPI. Although the objective has not been achieved, our analysis indicates that the CEGB has had some success in reducing the impact of the changed environment, in particular the greatly increased cost of fossil fuel.

6.71. Any cost reductions which have been achieved result from the aggregate of plans formulated at each power station. Table 6.1 sets out the planning performance, in terms of a comparison of SOP estimates and outturn, one year ahead and three years ahead, for three large power stations:

—Ferrybridge C, a large coal-fired station,

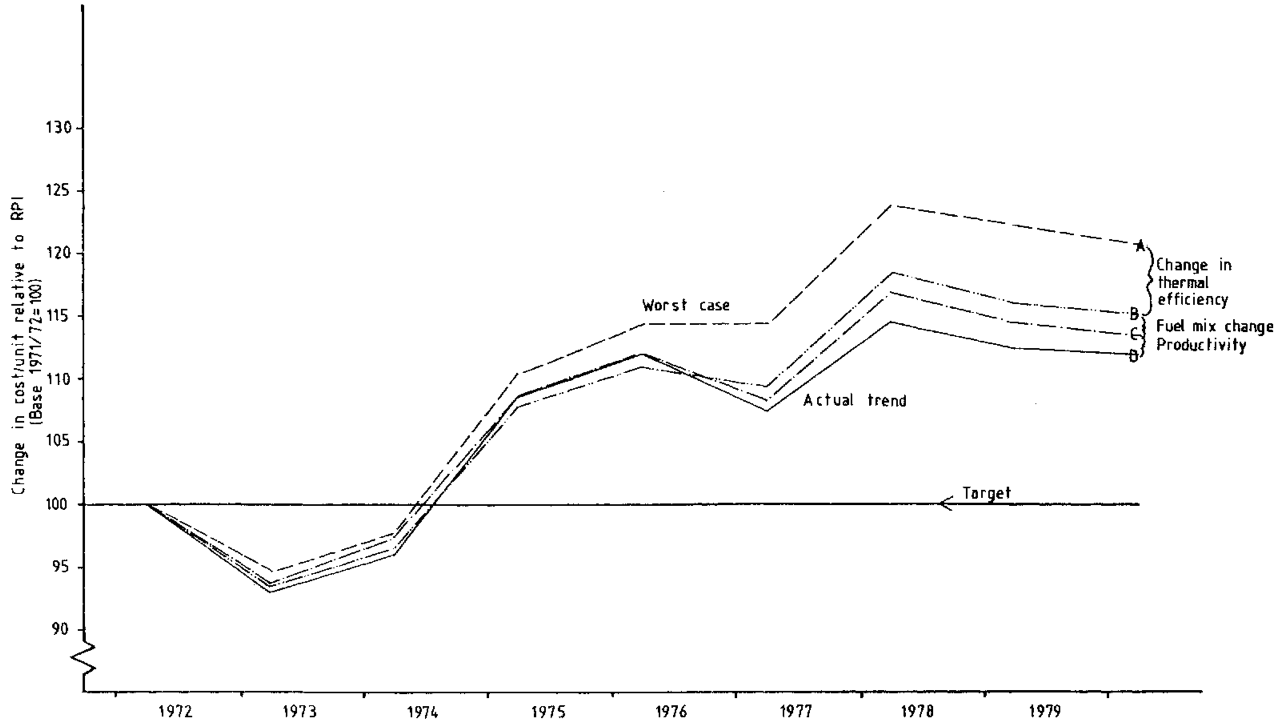
—Fawley, a large oil-fired station,

—Wylfa, a large nuclear station.

6.72. Table 6.2 presents data on planning performance for the three Regions associated with the three stations in Table 6.1, comparing planned estimates at outturns of annual average availability, winter peak availability, thermal efficiency and cost per unit supplied. For each of the three years shown, outturn costs per unit have been deflated, using the RPI, to the 'planned estimate' year price level.

FIGURE 6.9

Trend in Cost/Unit Relative to RPI = Comparison of Actual with 'Hands-off' Policy Since 1972



Sources: CEGB Annual Accounts; Digest of UK Energy Statistics; Department of Employment Gazette; Financial Trends; MMC Study.

6.73. Planning for target unit costs requires estimates of total cost and units supplied. The volatility of the unit production cost estimate in the September Outline Plan derives from a number of factors. First, the number of units actually supplied by a location although suggested by the national SYMAN simulation is not under station control, but in the event depends upon actual demand, the loading policy of National Grid Control, the performance of other stations and on the location's own availability. Secondly, the figures presented in the tables are from September Outline Plans and are not subsequently flexed (as is the Budget) to allow for changes in input costs and assumptions. Thirdly, the Outline Plans represent an offer to the Executive of particular options, from which the budget guidance is derived. The budget estimates may therefore be different from the planned estimate.

TABLE 6.1 **Planning performance for power station operational parameters**

		One year ahead predictions						*Three year ahead*	
FERRYBRIDGE 'C'		*75 Plan*	*1976–77*	*76 Plan*	*1977–78*	*77 Plan*	*1978–79*	*75 Plan*	*1978–79*
Annual Average	O	74·0	(−6·9)	59·29	(−8·8)	72·0	(+1·4)	72·0	(−15·3)
Availability (%)	E	79·5		65·0		71·0		85·0	
Winter Peak	O	86·0	(+16·2)	76·0	(−1·3)	79·0	(0)	79·0	(+1·3)
Availability (%)	E	74·0		77·0		79·0		78·0	
Thermal	O	35·10	(+2·3)	34·51	(−0·5)	34·85	(+0·1)	34·85	(+2·0)
Efficiency (%)	E	34·30		34·70		34·80		34·17	
FAWLEY		*75 Plan*	*1976–77*	*76 Plan*	*1977–78*	*77 Plan*	*1978–79*	*75 Plan*	*1978–79*
Annual Average	O	61·7	(−20·9)	68·0	(−10·5)	73·0	(−1·4)	73·0	(−8·8)
Availability (%)	E	78·0		76·0		74·0		80·0	
Winter Peak	O	84·0	(−3·4)	88·0	(+3·5)	91·0	(+5·8)	91·0	(+3·4)
Availability (%)	E	87·0		85·0		86·0		88·0	
Thermal	O	35·7	(+0·28)	36·4	(+2·2)	35·6	(0)	35·6	(0)
Efficiency (%)	E	35·6		35·6		35·6		35·6	
WYLFA		*76 Plan*	*1977–78*	*77 Plan*	*1978–79*	*78 Plan*	*1979–80*	*76 Plan*	*1979–80*
Annual Average	O	71·3	(−2·1)	53·9	(−28·3)	71·8	(−5·5)	71·8	(+10·0)
Availability (%)	E	72·8		75·2		76·0		65·3	
Winter Peak	O	82·0	(−6·8)	72·0	(−18·2)	78·0	(−2·5)	78·0	(−11·4)
Availability (%)	E	88·0		88·0		80·0		88·0	
Thermal	O	24·5	(−3·2)	25·2	(−1·2)	25·8	(−0·8)	25·8	(−1·5)
Efficiency (%)	E	25·3		25·5		26·0		26·2	

Source: The CEGB

O: Outturn
E: Estimate in Plan
Figures in brackets are % deviations of outturns from estimate.

6.74. An important element in maintaining planned operations derived from the national SYMAN simulation is the degree to which Regions achieve their predicted availability throughout the year. Annually each Region makes a commitment to Systems Operations to provide a given level of generation availability week by week through the following year. To prevent optimistic estimates the commitment is made on a 50 per cent probability basis, ie that availability is above commitment for 50 per cent of the time. Figures 6.10, 6.11 and 6.12 show the availability performance of each Region against target commitment.

TABLE 6.2 **Planning performance aggregated at regional level**

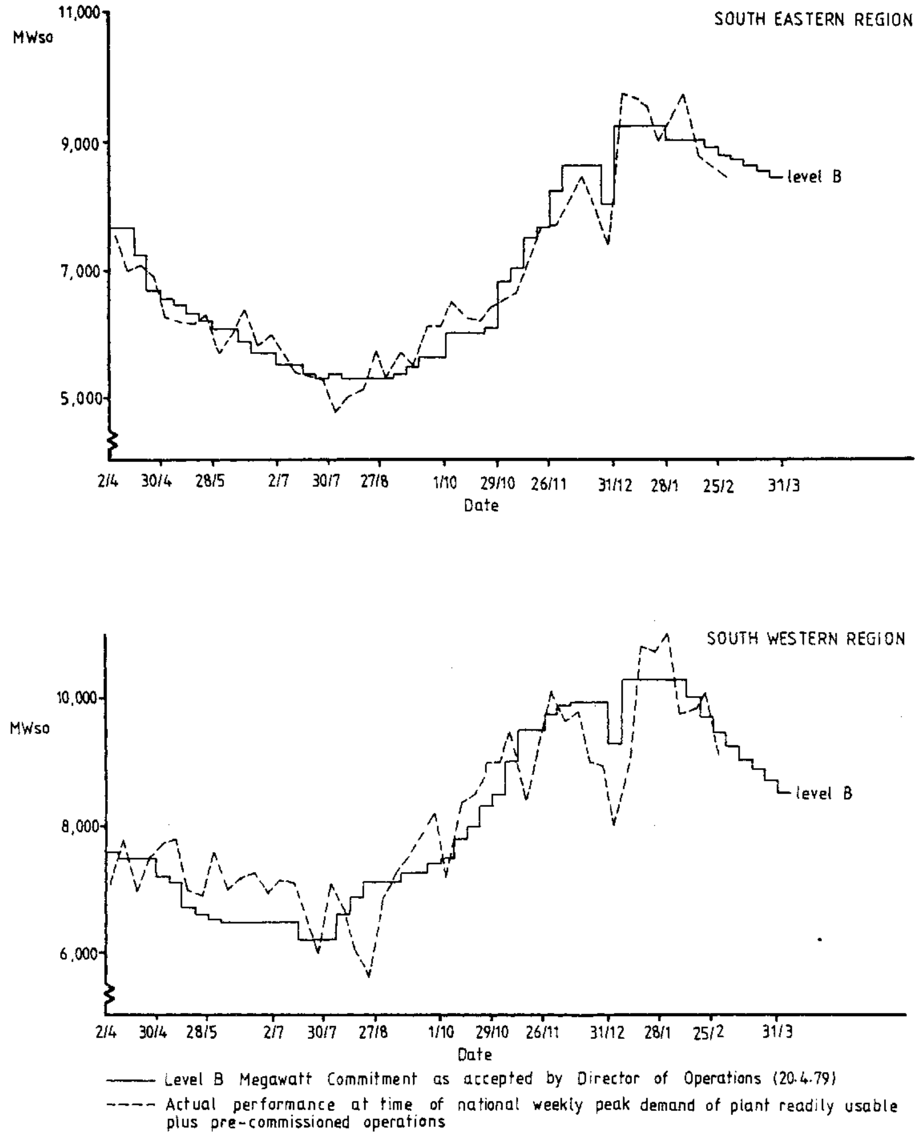
		One year ahead predictions						*Three year ahead*	
NORTH WEST		*75 Plan*	*1976–77*	*76 Plan*	*1977–78*	*77 Plan*	*1978–79*	*75 Plan*	*1978–79*
Annual Average	O	75·7	(+6·5)	71·4	(+2·0)	73·0	(−0·5)	73·0	—
Availability (%)	E	71·1		70·0		73·4		*	
Winter Peak	O	88·0	(0)	77·8	(−11·6)	85·2	(−2·4)	85·2	(0·4)
Availability (%)	E	88·0		88·0		87·3		84·9	
Thermal	O	30·83	(+2·3)	29·99	(−5·7)	30·98	(+1·8)	30·98	—
Efficiency (%)	E	30·13		31·81		30·44		*	
Cost per unit	O	1·0755	(+16·0)	1·4172	(+47·1)	1·4338	(+25·1)	1,4338	—
supplied (p/kWh)	E	0·9268		0·9631		1·1461		*	
Cost per unit Deviation when outturn adjusted by RPI*			(−5·4)		(+28·3)		(+5·4)		—
NORTH EAST		*75 Plan*	*1976–77*	*76 Plan*	*1977–78*	*77 Plan*	*1978–79*	*75 Plan*	*1978–79*
Annual Average	O	70·5	—	70·5	(−2·1)	70·4	(−2·2)	70·4	—
Availability (%)	E	±		72·0		72·0		*	
Winter Peak	O	76·8	(−7·5)	80·6	(−6·3)	80·5	(−4·2)	80·5	(−5·3)
Availability (%)	E	83·0		86·0		84·0		85·0	
Thermal	O	32·36	(−0·8)	31·89	(−2·1)	31·36	(−3·5)	31·36	(−4.9)
Efficiency (%)	E	32·61		32·68		32·51		32·98	
Cost per unit	O	1·0572	(+14·9)	1·2103	(+17·0)	1·3012	(+9·9)	1·3012	(+43·4)
supplied (p/kWh)	E	0·9198		1·0343		1·1837		0·9076	
Cost per unit Deviation when outturn adjusted by RPI			(−6·3)		(+2·0)		(−7·4)		(−5·9)
SOUTH WEST		*75 Plan*	*1976–77*	*76 Plan*	*1977–78*	*77 Plan*	*1978–79*	*75 Plan*	*1978–79*
Annual Average	O	63·7	(−6·3)	65·2	(−2·7)	69·1	(+6·3)	69·1	(+1·6)
Availability (%)	E	68·0		67·0		65·0		68·0	
Winter Peak	O	73·7	(−9·0)	79·0	(0)	82·14	(+4·0)	82·14	(−2·2)
Availability (%)	E	81·0		79·0		79·0		84·0	
Thermal	O	32·6	(−0·5)	32·69	(−0·2)	32·7	(+0·3)	32·7	(−0·9)
Efficiency (%)	E	32·78		32·75		32·6		33·0	
Cost per unit***	O	1·085	(+26·8)	1·198	(+19·4)	1·246	(+9·4)	1·246	(+60·2)
supplied (p/kWh)	E	0·856		1·0034		1·139		0·778	
Cost per unit Deviation when outturn adjusted by RPI			(+3·4)		(+4·1)		(−7·8)		(+5·1)

Source: The CEGB

E: Planned estimate, costs are in planning year base
O: Outturn, costs are in outturn year prices
Figures in brackets are % deviation of outturn from estimate

FIGURE 6.10

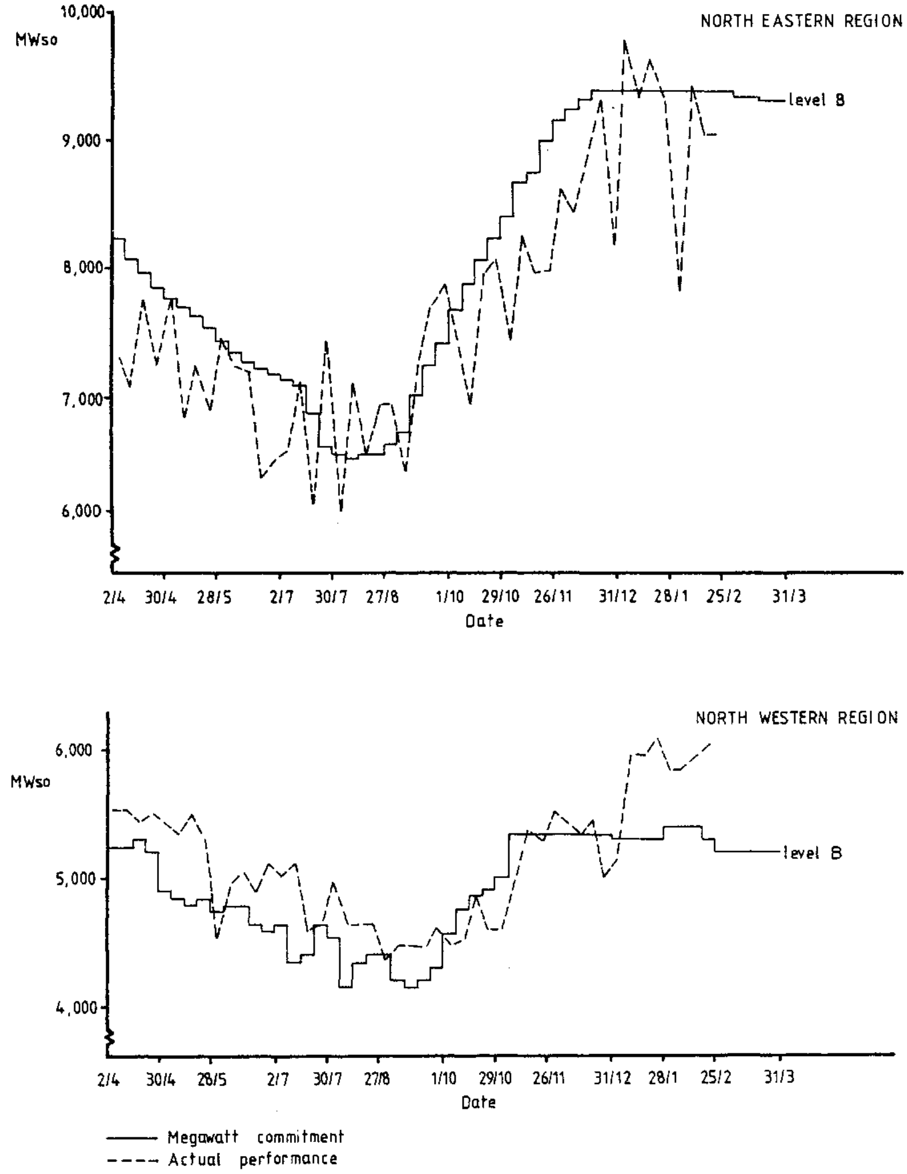
Megawatt Commitments 24 February 1980
A Comparison of Actual Performance to MWso Commitment



Source: CEGB

Figure 6.11

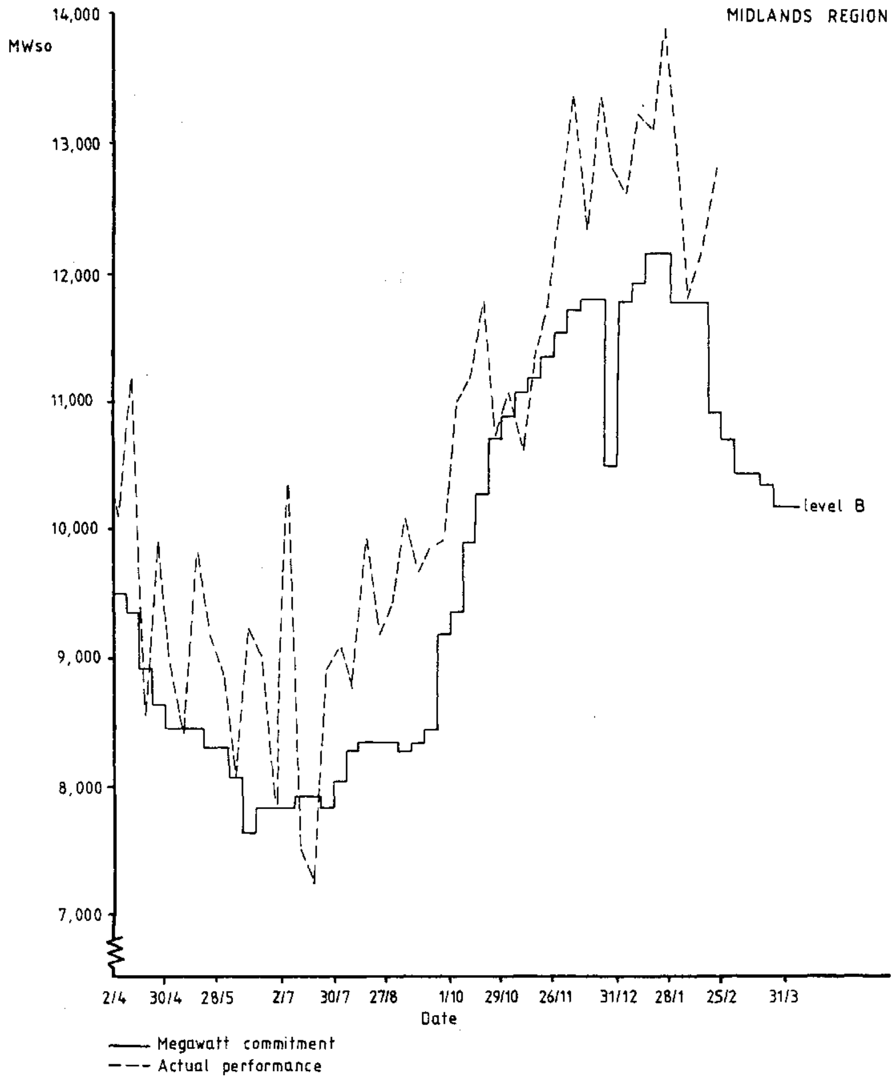
Megawatt Commitments 24 February 1980
A Comparison of Actual Performance to MWso Commitment



Source: CEGB

FIGURE 6.12

Megawatt Commitments 24 February 1980
A Comparison of Actual Performance to MWso Commitment



Source: CEGB

Short-Term Planning and Grid Control

Introduction

6.75. The final minimisation of costs is achieved over the very short-term by Grid Control with the planning and loading of generation on to the grid transmission system to meet demand. The inter-connected transmission system allows, in principle, optimisation of the total system. However, it is currently optimised separately in seven areas which are then co-ordinated centrally. The components are:

(a) *Seven Area Grid Controls* which are generally co-terminous with the Regions. They are responsible for managing both supply and demand in their area. They are also required to import from or export to other areas.

(b) *National Grid Control*, responsible for co-ordinating supply and demand nationally and ensuring cost minimisation and security of the main transmission system.

6.76. Apart from matching supply to demand, Grid Control is responsible for monitoring and maintaining the quality of supply as measured by three characteristics:

— Supply frequency, controlled by precise matching of the supply of and demand for electrical power. The current quality standards are a maximum variation of $\pm$ 0·5Hz.

— Supply voltage, controlled by matching the capacitative and reactive demands with the generation sources comprising both generating plant and the system itself. The current quality standard is defined by a maximum variation of $\pm$ 6 per cent.

— Maintaining correct clock time, controlled by frequency changes maintained over an interval of time.

The national supergrid network

6.77. The original grid system of the thirties was designed on the basis of areas self-sufficient in generating capacity. The supergrid, consisting of 400 kV and 275 kV links, was planned to allow bulk transfer, particularly from Yorkshire and the North Midlands to the South East, Lancashire and West Midlands. The self-sufficient areas were interlinked by a transmission system with capacity based on two criteria:

(a) Interlink capacity to maintain area security against internal loss of generating capacity, variation of demand and loss of transmission capacity. The system was designed against the risk of loss of a double circuit line.

(b) Provision of bulk transfer capability for minimising total generation cost. This implies a general bulk transfer from North to South and from Yorkshire to Lancashire.

The capacity for bulk transfer provided depends on the predicted level of demand and relative fuel cost. The system was designed before the rapid change in oil prices and is not therefore optimised to current conditions.

6.78. The supergrid now exhibits some limitations as the result of the changed generation pattern and late commissioning of some stations. This leads to minor cost penalties resulting from out of merit running.

- The N–S bulk transfer capacity will not be sufficient for future economic transfers, until the existing lines have been uprated.
- The Stella–Spennymoor link at 275 kV has insufficient capacity in the event of a west coast route fault. Low merit stations south of this link are run out of merit to provide security.
- The south coast route, which provides bulk supply for the south of England, was designed to be fed from Dungeness 'B', which is not yet commissioned, and Fawley, which is two-shifting. This line must now be fed by the Didcot N–S link which has limited capacity. To prevent over-loading of the Didcot link some units south of the link are run out of merit.

6.79. Each of the large conurbations is served with a 275 kV system feeding into the 132 kV and lower voltage local distribution system of the Area Boards. The 132 kV system has 25,000 MW of 'embedded generation', ie stations connected directly to the 132 kV system, some of which, particularly in London, have to be run out of merit order for security reasons. The out of merit running cost for the whole system in 1979–80 was approximately £12 million of which £2 million results from limits on the super-grid network.

6.80. Short-term planning at National and Area Controls is backed by longer-term operational planning of generation and transmission over the period from one week to five years ahead. The principal requirement is to ensure that the estimated system demand, in an average cold spell at a time of winter peak demand, can be met over the next five winters with sufficient margin to meet the Board's security criteria. It is necessary to ensure that, after making provision for the requirements of planned overhaul of generating and transmission plant, consumer demand can be met throughout the year at an acceptable risk.

6.81. A continual dialogue between the operating Regions and Headquarters ensures that complementary generation and transmission outage programmes are developed. As the formulation of the generation overhaul programme progresses a check is made of the Regional plant availability estimates against national demand estimates. Shortfalls are identified and programmes modified to provide sufficient capacity. Similarly systematic studies on the transmission configuration are carried out each week so that in the event the requirements of security and economy can be met in the Control phase.

PLANNING AT NATIONAL CONTROL

6.82. Planning at National Control consists of:

(i) assessment of supergrid security;

(ii) forecasting national demand;

(iii) loading Area Controls to match national demand at least cost; and

(iv) despatch of all gas turbine sets and pumped storage management.

6.83. *Supergrid security and transmission planning.* The final programme of transmission outages for maintenance and repair is planned up to six weeks ahead. The remaining available supergrid configuration is checked for security and stability by computer models. Contingency plans are developed for any credible faults which if they occurred would overload the remaining circuits. The plan may provide for post-fault measures, such as voltage reduction, the use of gas turbines for short periods, or re-switching. If these should not be sufficient to bring the circuit loads back within their capacity, then it would be normal to arrange for some plant to be run out of merit order as spinning reserve. Recently, to save cost, transmission risks have been increased by placing more reliance on post-fault measures, and in some cases the out of merit contingency is now only activated post-fault, reliance being placed on the thermal response delay of the circuit. This is done in consultation with the Area Boards and has resulted in annual savings of about £2 million.

6.84. *National demand forecasts for period ahead.* The forecast for the day ahead demand curve is determined by estimating demand at nine cardinal points throughout the day, corresponding to significant turning points in demand. At each cardinal point demand is averaged over a half hour period. Appendix 16 sets out the costing periods used by National Grid Control to optimise generation costs over the daily load curve. Provisional forecasts are made one day ahead and updated six hours and three hours ahead as the operating period approaches. Forecasts are made by three independent methods:

(*a*) An aggregate of Area Control forecasts.

(*b*) Using the computer program FORCE. This is based on a regression model relating historic weather and demand data. The inputs are four composite weather forecast variables:

— average spot temperature;

— effective temperature;

— cooling effect of the wind;

— effective illumination;

together with the day of the week (Saturday, Sunday, or working day), the time of year, and the last period demand.

(*c*) A manual extrapolation procedure called the 'Multiplier Method'. This starts with the actual demand at 2100 hours the previous day and applies a multiplying factor for each peak or trough period in the demand curve, weighted according to the weather forecast for the period. Weights are applied for the forecasts of temperature, wind, rain and cloud cover.

The final demand estimate is a matter of judgment, based on the outcome of these three forecasts.

6.85. *Accuracy of forecasting.* The three methods are equally accurate with negligible bias. The forecast standard deviation three to six hours ahead is about 1·5 per cent and on the day ahead about 2·5 per cent. Approximately 50–70 per cent of the error results from errors in the weather forecast. Figure

6.13 shows the performance of the short term forecast in terms of standard deviation through the year. There are always larger deviations in March, April and May because of the unsettled nature of spring weather.

6.86. *Load planning*. From the generating costs of the previous period and projected demand for the next period, National Control estimates the economic generating cost of satisfying demand. This cost is given to each Area Control as a planning cost. Areas offer to National Control their available and readily usable plant in merit order up to this cost.

6.87. Each Area returns to National Control the following information:

(*a*) Area estimate of demand;

(*b*) the generating output it can supply up to the quoted national cost;

(*c*) the resultant power transfer; and

(*d*) the incremental and decremental cost for increased or decreased output.

The total generation offered by Areas is then compared with the total national demand. If the planning cost originally quoted by National Control originally was correct, supply and demand will be in balance. Normally there will be a slight imbalance.

6.88. Using the incremental costs quoted by Areas, National Control will adjust transfers, and hence generation requirements, between Areas until any transmission constraint is reached, and until estimated demand is satisfied and a transfer balance is achieved. This procedure produces an approximation to a least cost solution.

6.89. Target transfers are set for each Area to maintain. National Control then monitors line loading, frequency and area transfer performance. Any large deviation will result in a requotation and modified inter-Area transfers.

6.90. *Despatch of gas turbine plant*. National Control now has responsibility for giving the despatch instruction for all gas turbine plant to its cost effective use. A recent study has shown that reduced spinning reserve and central co-ordination of gas turbines for periods of plant shortfall and for instantaneous matching of demand over very sharp peaks can produce savings of the order of £1·5 million over the winter period.

6.91. *Despatch of pumped storage*. The CEGB has decided no longer to use the Ffestiniog pumped storage for 'peak-lopping' but to hold it in place of spinning reserve. This saves off-load heat and reduces deloading penalties.

PLANNING AT AREA GRID CONTROLS

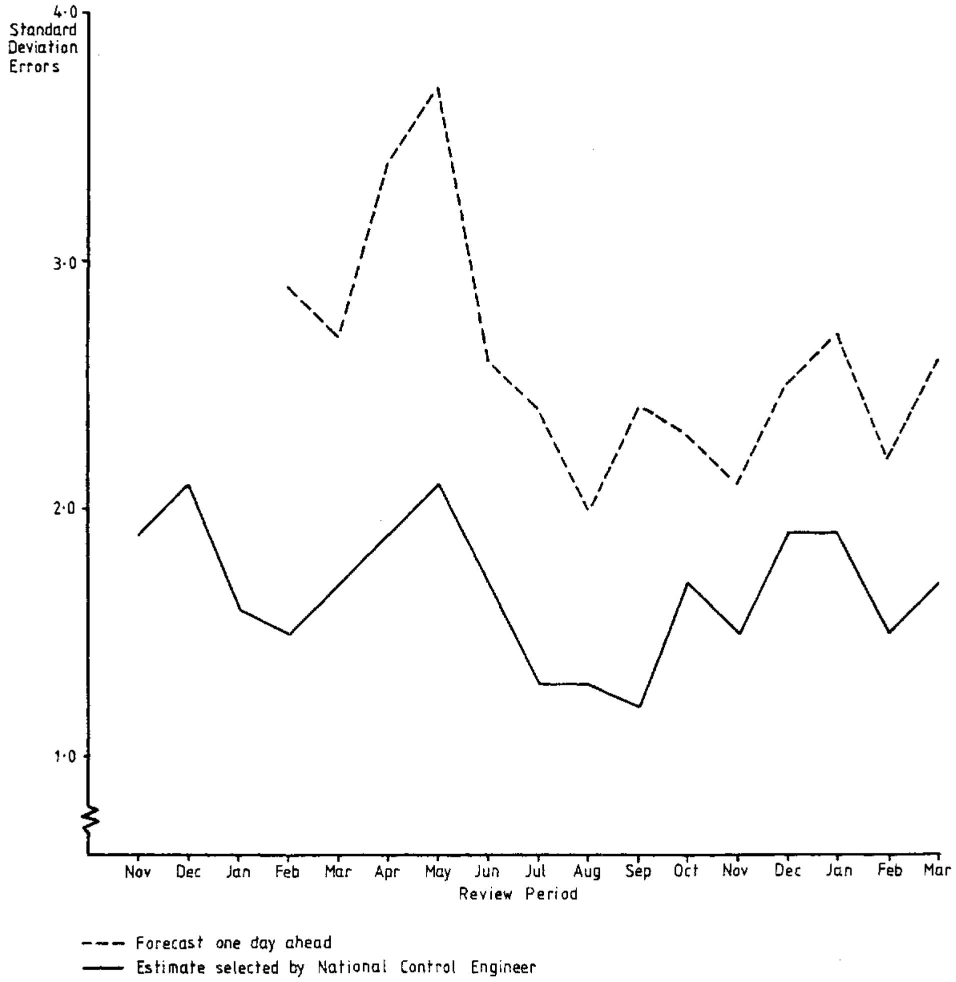
6.92. Area controls are responsible for the 275/132 kV grid system and for the security of supplies in their Area. Planning consists of four steps:

(i) assessing the security and stability of the available transmission network;

(ii) forecasting Area demand for the period ahead;

FIGURE 6.13

The Accuracy of Short-Term Forecasting Shown in Terms of Standard Deviation Errors



Source: CEGB

(iii) planned loading of generating sets to meet the inter-Area transfer at least cost; and

(iv) despatching sets to follow demand as it occurs and maintain target transfers.

6.93. The planning and assessment of the transmission network and demand forecasting is similar to that in National Control. There is a variation in forecasting methods between the Areas but methods based on the weather forecast similar to 'FORCE' and 'Multiplier' are used. Forecast errors are of the same order as the national forecast.

6.94. *Load planning and scheduling.* Load planning starts with daily updating of the latest merit order calculation by the MOCAL program, run monthly at Regional HQ, for the generating sets in the Area. The daily updatings are modified by adjustments to costs for the present status of the plant. Plant status reports, set by set, are given to Area Control by Regional Operations and the Control Engineers at the power station.

6.95. Tables are produced which list for each generating set the total marginal cost at full load (Table A) and the incremental and decremental margin cost for load changes (Table B). National Grid Control gives to each area a generating cost per unit which it expects to be the marginal cost for the next period. Sets are then scheduled in merit order of cost up to the quoted national cost. In some cases sets may be planned to run out of merit order for a variety of reasons, examples are:

—transmission security (including the problems of embedded generation, see paragraph 6.79); and

—station inflexibility.

6.96. The result of scheduling will leave some Grid Control Areas with a supply deficit and others with a supply surplus. These are balanced at National Grid Control by reference to the quoted Area incremental costs. National Control issues each Area with a target import or export transfer which will balance national demand.

6.97. *Despatching.* A prediction of the demand curve profile is obtained for the period ahead, and sets are despatched on-load or off-load to balance the changed area demand and maintain the target import or export transfer. This is entirely the responsibility of Area Control unless marginal generating costs exceed the national quote. In this event National Control may re-optimise by changing the target transfers. There is a standard national procedure for all Areas to respond to a frequency deviation by biasing the planned transfer by 50MW for a 0·1 per cent deviation in frequency. However, manual frequency control, on which this procedure depends, is difficult and sometimes leads to 'hunting'[1].

[1] 'Hunting' is temporary oscillation caused by overcompensation for frequency changes.

MONITORING AND PERFORMANCE OF THE CONTROL FUNCTION

6.98. The effectiveness of short-term planning by Grid Control is monitored daily, monthly and annually. The parameters include:

- — accuracy of demand forecast—mean and standard deviations;
- — utilisation of high merit plant;
- — out of merit running;
- — use of gas turbines;
- — marginal cost;
- — frequency control performance.

A post-mortem simulation is run to compare marginal cost achieved against ideal cost given available plant. Table 6.3 shows the out of merit costs for the SE Region for July 1980.

Total generation costs in that Region for the month were £35 million.

TABLE 6.3 **Out of merit generation costs for SE Region, July 1980**

Cause	*Cost*
LEB security	£39,290
CEGB security (cable fault)	£3,580
SYSTEM INFLEXIBILITY	
— Lost plant	
— Low frequency start of gas turbines	
— Low national demand forecast	£50,590
STATION INFLEXIBILITY	
— Shut down time too long to follow demand	
— Cold plant brought on early	
— Overnight running	£110,940
OTHER STATION CAUSES	
— Station testing etc	£19,100
TOTAL FOR MONTH	£223,500

Source: CEGB.

CENTRAL LOADING AND DESPATCH

6.99. Although we believe that the present procedures produce a good low cost configuration, there are some marginal defects which prevent the achievement of absolute minimum cost. The three main factors are listed below:

(*a*) Over the six month time scale the system costs are optimised nationally. However in the short term, costs are first optimised separately by each Area, including running spare, based on Area demand estimates. Costs are placed in a national context by means of inter-Area transfers. Each Area continues to optimise separately as it follows demand and maintains target transfers. The two stage optimisation must result in some cost penalties.

(*b*) The Area transfers are re-optimised in a national context nine times daily, and then on a basis of an integrated half hour demand at a demand turning point. Some cost penalty must result from this imprecise tracking of demand profile.

(*c*) The merit order produced by the national SYMAN simulation is a true system marginal cost merit order. This is adjusted for heat rate and current fuel costs monthly at Region and daily and hourly at Area Control. However, the method of adjustment is only approximate and the operational merit order does not reflect ultimate variations in system marginal cost. There is a cost penalty in the divergence from system marginal cost ranking.

CENTRALISED SCHEDULING AND DESPATCHING

6.100. The CEGB recognises these limitations and is investigating the possibility of centralised scheduling and despatching of generating sets. A computer scheduling program GOAL (Generator Ordering and Loading) is being developed. It will follow the forecast demand profile and schedule dynamically, the available generating capacity at minimum cost. The costing would explicitly include off-load heat, no-load heat, peak-to-trough adjustment factors and some additional maintenance costs.

6.101. The investigation of central despatching is based on the development of on-line optimisation of generator loading. The proposed system would monitor in real time the current operating parameters of each set—load, spare, steam pressure and temperature, circulating water temperature, etc—and hence predict short-term availability and response time.

6.102. The program would then optimise the loading of sets nationally with respect to forward demand, forward availability and current heat costs. Final despatching to follow actual demand can then be achieved at area level, as at present, or nationally. National despatching would have the advantage of optimising the use of the very large capacity represented by the new pumped storage scheme under construction at Dinorwic.

6.103. Trials have been carried out to test the feasibility of Central Loading and Central Despatching. These trials demonstrated its feasibility but also showed that certain areas were insufficiently developed for immediate implementation, in particular:

—late and unreliable updating of basic data;

—computer system not reliable enough;

—frequency control difficult and unstable.

Frequency control will be very much improved when the pumped storage scheme at Dinorwic is commissioned. Computing reliability may require large capital expenditure to provide a dedicated computer system with sufficient spare capacity. It is proposed that the first step should be to use the GOAL program off-line for day ahead and weekend planning, especially for planning over bank holidays.

6.104. The successful implementation of central scheduling is expected to produce savings of £5–£7 million annually and the implementation of central despatching to produce equivalent additional savings. These savings should be seen in the context of the annual generating cost of about £3,300 million.

Conclusions

National energy studies and the merit order

6.105. We believe that the merit order based on system marginal costing is an appropriate concept for cost minimisaton. However, under some large divergences from the assumed conditions it might be better to revert to a merit order based on thermal efficiency for day-to-day planning; and we suggest the CEGB should investigate this. The alternative would be to run the SYMAN simulation suite more frequently than the current six month interval.

6.106. We are satisfied that a simulation model of the complexity of SYMAN is necessary in order to produce savings from the system at the margin. Although the current iterative model does not guarantee a true optimal solution it is clear from the rapid reduction of costs during iteration and the relatively small difference between successive iterations after convergence, that the procedure produces a good low cost allocation.

6.107. There are two areas of development which may warrant some study:

(*a*) The model does not treat transmission losses in a realistic way. The economic transport of power could be optimised in a manner similar to that used on COFAL.

(*b*) The model is too complex to be run on a day-to-day basis to update the system marginal cost merit order. However, a system for ranking station availabilities and fuel source availabilities on a Regional basis might indicate the levels of divergence at which the adjusted system marginal cost merit order is no longer likely to produce a lower cost solution than thermal efficiency merit order.

Five year planning

6.108. We are satisfied that the Board has an effective operational planning system and that the outturn is adequately monitored. The procedure produces quantitatively based targets within the range of feasibility, justified in terms of costed work projects. The system can respond quickly to changes in planning assumptions. We have been particularly impressed by the quality of commercial judgments in planning at power station level.

Short-term planning

6.109. The procedures for short-term planning of electricity generation and supply are effective in maintaining the quality and security of supplies at a cost consistent with good management. The short-term demand forecasting procedures do not lead to an unacceptable level of error. A significant proportion of the error results from errors in the weather forecast.

6.110. The Board is obtaining cost savings at the margin in a number of ways—by recognising supergrid transmission costs in the system marginal cost simulation, by slightly decreasing security in transmission, by co-ordinating the use of high cost gas turbines centrally, and by using pumped storage instead of spinning reserve.

6.111. We recommend that the CEGB should undertake a comprehensive cost benefit study of central on-line scheduling and despatch of plant, and if the net benefits are consistent with its normal criteria for return and pay back, should develop a plan for full implementation including a study to secure appropriate computer system reliability.

THE MONOPOLIES AND MERGERS COMMISSION

Central Electricity Generating Board

A Report on the operation by the Board of its system for the generation and supply of electricity in bulk

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CHAPTER 7

Fuel procurement

Introduction

7.1. Our terms of reference require us to have particular regard to the Board's purchasing policies in the more general consideration of whether without reducing the standard of service provided it could improve efficiency and reduce costs, or mitigate the effects of any increases in costs. In this chapter we consider the Board's procurement policies for coal, fuel oil, natural gas and nuclear fuel. In 1979–80 purchases of these (including transport and nuclear fuel reprocessing) were about 60 per cent of total costs, and hence their most important component. In recent years all fuels have risen substantially in price, and changed in relative importance as fuel for generation. We examine the Board's purchasing policies towards each, and note here that our interest is in its effects on costs. We do not believe the quality of service has been affected by the Board's policies for fuel procurement. The recent pattern of fuel consumption is shown in Table 7.1.

TABLE 7.1 **Fuel consumption and cost in the CEGB**

	Fuel consumption mtce*						Cost £m
	1973–74	*1975–76*	*1976–77*	*1977–78*	*1978–79*	*1979–80*	*1979–80*
Coal	63·7	67·5	70·6	70·3	75·5	80·6	2,185†
Fuel oil	24·6	16·9	14·1	16·3	17·6	12·3	489
Natural gas	2·5	3·8	2·0	2·1	0·5	0·9	
Nuclear	8·0	8·7	10·7	11·7	10·6	10·9	234
Total	98·8	96·9	97·4	100·4	104·2	104·7	2,908

Source: The CEGB Annual Reports.

* Million tonnes of coal equivalent.
† Includes cost of transport (7·6 per cent of total coal cost).

Coal and Oil

7.2. Coal has always been the most important fuel, and in recent years its share of the total fuel bill by value has risen from about 65 per cent in 1973–74 to 75 per cent in 1979–80. It is expected to be about 80 per cent in 1980–81. Relative price movements have been the main reason for the changing importance of the different fuels. Table 7.2 shows the price movements of coal and oil used for generation.

7.3. The increases in coal and oil prices have been considerable. Since 1973 the price of oil for burning has risen 28 per cent faster than that for coal. As a consequence the Board has sought to reduce its dependence on oil, and this halved its importance as a fuel for generation from 1973–74 to 1979–80 (from a 24 per cent to a 12 per cent share).

Coal

7.4. The National Coal Board provides over 90 per cent of the coal used by the CEGB, the remainder coming from private United Kingdom sources

TABLE 7.2 **Index of average prices of fuels used by the electricity industry in Great Britain (£/tonne)**

		Oil for	
	Coal	*Burning*	*Gas turbines*
1973	100	100	100
1974	139	240	215
1975	213	310	271
1976	254	355	303
1977	295	441	384
1978	330	425	394
1979	380	487	413

Source: Digest of United Kingdom Energy Statistics 1980. Department of Energy. (The index is derived from the price information provided annually by the Industry to the Department of Energy.)

or from abroad. Coal for the CEGB accounts for over 60 per cent of the NCB's total production and over 80 per cent of its production of steam coal. A further 8 million tonnes is sold to the South of Scotland Electricity Board. Three quarters of the CEGB's coal supplies are delivered by British Rail and produce about one quarter of BR's freight revenue; thus the operation and financial position of the three nationalised industries are closely interdependent.

7.5. Coal supplies to the CEGB have been as follows:

TABLE 7.3 **Source of coal supplies (million tonnes)**

	1975–76	*1976–77*	*1977–78*	*1978–79*	*1979–80*
NCB	65·2	69·3	68·5	69·1	77·9
Other United Kingdom	1·4	0·5	1·5	1·4	1·5
Imports	3·4	0·8	1·3	0·3	2·4
Total coal delivered	70·0	70·6	71·3	70·8	81·8
Total coal consumption	67·5	70·6	70·3	75·5	80·6

Source: The CEGB's Annual Reports.

PURCHASING ARRANGEMENTS IN THE REGIONS

7.6. Twice a year the CEGB HQ in conjunction with Regions carries out a major exercise to determine a plan of fuel purchasing at the lowest cost. The detailed plan is formulated within a longer term policy. This exercise is described in greater detail in Chapter 6. The resulting plan is discussed with the NCB and BR, and once the global programme has been agreed it is passed to the CEGB Regions, the BR Regions and the NCB Areas for implementation. In the four Regions of the CEGB with significant railborne deliveries tripartite meetings take place once a month to plan supplies for the next month using the six month plan as a basis but taking into account local difficulties such as power station plant breakdowns, changes in demand for electricity, falls in the NCB's output or problems of BR. For these operational reasons the actual flows at any particular time may be quite different from the average flows set out in the six month plan. The Regions, however, do look back to see how flows have diverged. They also compare their coal costs in pence/therm against costs implied in the plan.

7.7. The national plan is regarded as providing standards every six months against which the Regions have to operate. The CEGB feels that it would not be cost effective to produce the plan at intervals of less than six months.

7.8. Regional fuel supplies officers are responsible not only for the quantity of coal purchased on a day-to-day basis but also for ensuring that the CEGB receives value for money from the NCB. The price of each coal is given by the NCB's Industrial Coal Price Structure (ICPS) (see paragraph 7.20), and reflects the calorific value of each type, other technical properties, and a small geographical element. There is little price negotiation at Regional level but the CEGB checks the quantity and quality of coal received and reports discrepancies from the quality paid for. If there has been a persistent discrepancy the CEGB and the NCB will negotiate an adjustment at Regional level. The sums of money involved are not negligible, for instance a 1 per cent difference in the ash content results in 60 pence per tonne difference in some coals. In the Midlands Region this could amount to £40,000 per week. It could also affect the quantity of ash to be disposed of, and its cost. In 1979/80 coal quality claims in South East Region amounted to £3,250,000.

RELATIONSHIPS WITH THE NCB, AND THE PRESENT PRICING ARRANGEMENTS

7.9. Despite the close connection between their businesses, and the effective working Regional arrangements described above, we understand from both the CEGB and the NCB that in the past there have been serious divergences of view, particularly regarding coal prices and pricing policies. In the light of the decline of the coal industry during the 1960s, and the emergence of oil and nuclear fuel as competitive sources it is perhaps understandable that the two industries might have had strongly held but differing views of the future. It is not our purpose to examine this history, but we mention it as being important for a fuller understanding of the present arrangements for the supply of coal, and in particular the CEGB's plans and ability to import which we deal with in more detail in paragraph 7.18. We also note that whether because of this history or not the industries have been unable to make long term arrangements for coal supply. The CEGB has told us this is because the NCB has been unable to guarantee prices, and so the CEGB has been unable to guarantee a sufficiently high minimum annual purchase of coal to satisfy the NCB.

7.10. The present arrangements for the pricing and supply of NCB coal are contained in a joint understanding made in October 1979 and intended to last until March 1985. The principles of the understanding which is to guide the CEGB and the NCB are:

'(i) NCB will use their best endeavours to supply 75 million tonnes per year of suitable coal to CEGB.

(ii) CEGB will use their best endeavours to take from NCB all suitable coal up to a total of 75 million tonnes per year, providing that the average pithead price of NCB coal sold to CEGB under the Industrial Coal Price Structure increases by no more than the rate of UK inflation.

(iii) CEGB will buy from indigenous and overseas sources such additional quantities of coal as they judge necessary to secure adequate fuel for generation and to augment stocks. These purchases will be arranged so as not to jeopardise CEGB's ability to purchase the quantities of NCB coal mentioned in (ii) above.

(iv) CEGB will keep NCB informed, at regular intervals, of their plans to secure imported coal and the outcome of negotiations. CEGB will also make available such further relevant information as NCB may reasonably request and which can be provided without breaching commercial confidence.

(v) NCB will keep CEGB informed, at regular intervals, of their plans to export industrial coals. NCB will also make available such further relevant information as CEGB may reasonably request and which can be provided without breaching commercial confidence.'

7.11. A supplement sets out the necessary conditions, including the price adjustment mechanism, which are required for the understanding to operate without friction. The supplement also states that if after March 1980 the NCB is unable to contain prices within the agreed ceiling then both sides will meet to discuss how much coal the CEGB will wish to take in the financial year immediately following the price increase. Both the CEGB and the NCB have made it clear to us that the understanding is not an enforceable contract.

7.12. The CEGB has told us that in reaching the understanding it had the following objectives:

(i) to establish a more sensible trading relationship between the two Boards;

(ii) to exercise some restraint on the price of coal to prevent the headroom created by the price of oil from being taken up; and

(iii) to obtain the NCB's acceptance of the Board's right to import coal.

7.13. The Board explained that there were a number of elements in (i). First, it considers that for all intents and purposes the NCB is a monopoly supplier of coal, and there is no authority in the United Kingdom which supervises or approves the NCB's prices. Secondly, it has been concerned for a long time over the structure of coal prices, and believes that electricity consumers subsidise uneconomic pits (see paragraph 7.22). It has located coal-fired stations in areas of low cost coal production, but considers that the NCB has not reflected these low costs in its local coal prices. Thirdly, it believes itself to be the 'residuary legatee' of NCB costs, so that if the NCB makes deals advantageous to other coal users it may be partly at the expense of electricity consumers. It believes that if the present understanding works satisfactorily it might establish a basis for removing or mitigating the disadvantages arising from these matters.

7.14. In explanation of (ii) the Board said that prior to the understanding, coal prices had gone up 35 per cent in 17 months, and it was concerned that the substantial increase in oil prices might give 'headroom' for similar increases in coal prices (see Table 7.2). It was its intention in assuring the

NCB, as far as it could, of a minimum purchase of 75 million tonnes a year, to provide a strong inducement to contain price rises within the level of inflation.

7.15. On the matter of coal imports the CEGB told us that from time to time Government wishes, overt or covert, have had a strong influence on the quantity of foreign coal burnt at power stations, and when political constraints permit it buys modest quantities of foreign coal at prices which are significantly lower than those of comparable NCB coal. As an example of this influence it drew our attention to the statement in September 1976 of the then Under Secretary of State for Energy. He said that the CEGB had agreed with the Department of Energy not to enter into coal import contracts without first consulting the Department, that the Secretary of State for Energy would decide if imports were necessary, and whether they would be handled by the CEGB or the NCB; and that the CEGB and the NCB had agreed to negotiate the joint management of existing import contracts. The results of this negotiation were reported in Hansard (Column 588) on 5 March 1979. The CEGB has told us that it no longer requires the Secretary of State's approval to import coal.

THE VIEWS OF THE NCB

7.16. In making the arrangement the NCB also had objectives which it has explained to us. These comprise advantages in the short and long term. For the short term it saw a possibility that the recession would reduce the demand for coal, while at the same time the world coal market was developing rapidly and imports, even though limited in quantity, could be obtained at lower prices than coal could be produced at some United Kingdom pits. It felt its current levels of output to be at some risk. It was in the early stages of an incentive scheme to increase output, and wished to increase stocks to be able to deal with short-term demands. A reasonable assurance of at least 75 million tonnes as an annual purchase, was, therefore, advantageous to it. In the longer term it planned to develop coal, and was making substantial investments in existing and new pits, so if the understanding worked and led to more satisfactory commercial relationships with the CEGB it felt it would help to protect the investments.

IMPORTS OF COAL

7.17. We have shown in Table 7.3 imports of coal from 1975–76 to 1979–80, and in paragraph 7.15 described the restrictions operating until recently on the CEGB. During the 1970s imports have had only a small share of the market except in years of shortage arising from a miners' strike. We understand from the CEGB and the NCB that the import of coal as a permanent supplement or competitor for some proportion of United Kingdom mined output has only become a real possibility in the 1970s. In addition to restraints arising from government policy on the CEGB's ability to import there are problems arising from limited port facilities, and sometimes from price levels. A sustained and substantial import share would require investment to expand the port facilities. In 1974 the Board considered investment to increase its import capability, but concluded that in the circumstances it would not be economic to do so. It is now giving further consideration to this possibility.

7.18. As imports may affect both the market position of the NCB and the cost of coal for generation, particularly in the short term if price increases for United Kingdom coal exceed the rate of inflation, we asked the CEGB what potential it saw for imports. Its view was that over the next few years it could increase the level of imports to 10 million tonnes a year without too much difficulty or undue effect on price. If the CEGB sought to import more than 10 million tonnes a year, that action might raise prices more sharply. Transport costs were also important. Adjusted for calorific value the delivered cost of imports was in the summer of 1980 only two thirds of the delivered cost of NCB coal for stations on the Thames estuary.

OTHER SOURCES OF UNITED KINGDOM SUPPLY

7.19. Currently the CEGB obtains about 1·5 million tonnes a year of United Kingdom coal from non-NCB supplies. These are from mines licensed by the NCB, some sites where the NCB has no rights, washing of tips and the reclamation of old railway goods yards which were largely constructed of coal. The price of coal from these sources is never less than 10 per cent below the NCB price. The Board estimates that at most it could obtain another 1 million tonnes a year from these sources.

THE PRICE OF NCB COAL

7.20. The price paid by the CEGB is determined from the NCB Industrial Coal Price Structure (ICPS). The ICPS reflects the calorific value of each type of coal, the NCB Area base price, and adjustments for ash and sulphur content and grade. (A fuller explanation is given in 'Coal—The Price Structure' prepared by the Confederation of British Industry, 1 March 1980.) The adjustments for ash and sulphur content and grades are common to all NCB Areas, but there is some slight variation in the Area prices. The CEGB has supplied the following data which show typical average pithead prices of coal purchased by it from coalfields spread across Great Britain. The 'pithead' price paid by the CEGB is before delivery by road or BR, and is determined from the ICPS.

TABLE 7.4 **Typical average 'pithead' price of coal supplied to the CEGB**

	£/tonne		*pence per gigajoule**	
Supply coalfield	*Jan 1970*	*March 1980*	*Jan 1970*	*March 1980*
Scotland	5·26	36·50	20	147
North East	4·70	32·78	19	130
Yorkshire	3·85	30·64	15	128
North Midlands	3·85	31·59	16	131
South Midlands	4·13	28·86	18	131
Western†	5·58	33·07	22	133
South Wales	5·63	34·44	22	134
Great Britain Weighted average	4·20	31·46	16	130

Source: The CEGB.

* Corrected for calorific value.
† The Western coalfield is not on a comparable basis for the two dates because of the merger of the Staffordshire and North Western Areas in 1973–74.

7.21. When corrections are made for varying calorific value, prices at March 1980 showed only a small difference between coalfields, except for Scotland. Taking the North Midlands as a base of 100, the Scottish coalfields were 12 per cent higher and South Wales 2 per cent and the remainder varied between 2 per cent lower and 1 per cent higher. The table shows how the area price variations have narrowed over the decade.

7.22. We have noted in paragraph 7.13 the CEGB's concern over the price structure. In elaboration it said it would like to see the NCB become a streamlined producer of economically priced coal with no cross-subsidisation of uneconomic pits by profitable ones. It argues that one means of achieving this would be for the price structure to be based on costs of production at pits, believing that this would give the correct economic signals for generating electricity using the cheapest sources of fuel, and in the long run enable it to obtain full benefit from its investment decisions. It was its view that such a structure would also give the NCB correct economic signals which would eventually be reflected in its investment decisions, and the closure of high cost pits. It is prepared to consider other forms of pricing that would achieve the same objective. While it understood the NCB's wish to charge a market clearing price and achieve its financial target, the CEGB felt in some difficulty because it had inadequate information as to how these factors operated as regards the prices paid by it. It also made the additional point that earlier the NCB had reflected cost differences between coalfields to a greater extent in the price structure, but during the 1970s these differentials had been substantially narrowed.

7.23. To examine the CEGB's claim that cross-subsidisation of uneconomic pits caused its generating costs to be higher than they would otherwise be, particularly when its ability to import cheaper coal is limited, we asked the Board for its estimate of the amount by which costs were raised, and the method by which it was calculated. We also asked for its estimate of the amount of steam coal which it believed was being sold at lower prices than it paid. In its reply the Board emphasised that an accurate assessment of financial penalties to it of the NCB's pricing is difficult to make because of the lack of information, and because of the NCB's reluctance to disclose costs of production at individual collieries. Nevertheless, it believes that publicly available information confirms the view that overall productivity at individual collieries shows wide variations. To estimate the financial effects of the cross-subsidisation it has developed a marginal cost curve from which the costs per tonne of coal, excluding interest and grants, could be assessed for each increment of production. From this, and using 1978–79 data, it calculated that about 3 million tonnes from marginal pits would be sold to the CEGB in a typical year, and that the NCB's production costs of this coal might exceed the price by about £35 million. This provided a crude order of magnitude of the extent to which the high cost collieries are being subsidised by profitable low cost collieries. On the question of steam coal sold at prices lower than it paid, the Board had been told by the NCB that the quantity was about 4 million tonnes a year, and the CEGB believed this could be as much as 40 per cent of the industrial coal market apart from the generating boards.

7.24. We have not been able to assess the accuracy of the estimate of the amount of cross-subsidisation, nor if, and to what extent, other steam coal purchasers cause the CEGB price to be higher because they have lower prices. To do both would require a thorough examination of the costs of the NCB and the economic and other justifications for the present level and structure of coal prices. However, we have been able to put these issues to the NCB and it has described to us its pricing policies. It agrees that some cross-subsidisation of uneconomic pits takes place, but does not accept the basis of the CEGB's calculation, and states that the cross-subsidisation is lower.

7.25. In explanation of its pricing policies the NCB says it is fully aware of the CEGB's views. By way of background it has said that it is not a monopoly supplier of fuel and has to take into account import prices as well as oil and nuclear supplies. It also has to aim at the financial target set by the Government, which is to break even by 1983–84 after interest payments, and with assistance only of social cost grants. At 1979–80 prices this effectively means turning an operating loss of £75 million into a profit of £200 million while at the same time increasing the proportion of investment which is financed from operating income. There are also substantial social costs attached to the consequences of production and investment decisions. Finally, it has drawn our attention to the provisions of Section 1(i)(*e*) of the Coal Industry Nationalisation Act 1946 and Article 60 of the ECSC Treaty, dealing respectively with undue or unreasonable preferences and with discriminatory practices. It believes that if prices were related to costs at particular pits there would not be enough low-cost coal to meet demand, with the result that supplies could be dealt with only by allocation—a process which by its nature could provide fertile ground for allegations of unlawful preference or discrimination.

7.26. The NCB told us that pit-based pricing is not feasible because, even in the low-cost central coalfields where the major proportion of generating capacity is located, the productivity of individual pits varies considerably due to geological conditions, and changes rapidly as coalfaces become exhausted and need to be renewed. (The average life of a coalface is 15 to 16 months.) The level of profitability is such that there is no scope for making price reductions in the central coalfields. NCB published accounts show that of the eight areas in the central coalfields five make operating losses. While it might appear that prices in other areas should be raised substantially to cover higher costs, it does not believe higher priced coal could be sold. Nevertheless, the NCB stressed that it has identified the coalfields where it believes continued production would be competitive with oil, and is expanding output and investment in them.

7.27. The NCB confirmed that steam coal is sold to some customers at prices less than those paid by the CEGB. The NCB believes that these lower prices had been justified on commercial grounds.

ISSUES RAISED BY THE PRESENT PRICING ARRANGEMENTS FOR COAL

7.28. We are aware that the issues raised by the pricing arrangements between the CEGB and the NCB go wider than the terms of reference of our investigation. As our interest is with their effects on the CEGB's efficiency and costs, we only note that the arrangements also have implications for the costs of the NCB, and through these there are consequences for the efficiency of industries using coal and for other final consumers. The two aspects of concern to us arise from the terms of the understanding described in paragraph 7.10, and the pricing structure described in paragraph 7.20, and discussed in paragraphs 7.22 to 7.26.

7.29. Price variation mechanisms are frequently included in purchasing arrangements and may have advantages for sellers and buyers. If both agree, for whatever reason, that long-term arrangements are desirable, then in a period of rising or falling prices such mechanisms may ensure that the seller is able to maintain the value of the arrangement, while the purchaser receives some assurance that price changes are determined in an acceptable manner. In freely functioning markets, and where there is effective competition, such mechanisms may raise no issues of public concern. However, where buyer or seller or both have the power to influence prices in the markets for their products and the necessary inputs then price variation mechanisms, if designed in certain ways, may be easy devices for passing on costs which might have been avoided, and in the long run may weaken the effectiveness of the market mechanisms which induce producers to seek maximum improvements in productivity. As both the CEGB and the NCB have substantial power to influence prices in their markets, at least in the medium term, it is our view that these questions are raised by the pricing arrangements between them.

7.30. One difficulty in forming a view is that the understanding has only been in operation for just over one year, so there is little experience on which to base judgments. The NCB has told us that in the first year the price of coal to the CEGB went up by less than the increase in the RPI over the period. The CEGB believes that in a period of rapidly rising oil prices the understanding will impose a restraint on the price of coal purchased by it. It also believes that the restraint will be effective because the NCB has recognised its right to import coal. If the CEGB is correct, and the mechanism imposes an effective upper limit on the price of steam coal, then this could benefit electricity users whatever effect it might have on the NCB or other coal users.

7.31. A further point is that both parties would like the understanding to be effective and provide the foundation for a more harmonious long-term relationship which could result in substantial benefits to both, and to the consumers of their products. Finally, as the mechanism is to operate for only a relatively short period, if it should turn out to have detrimental consequences they will be limited.

THE TRANSPORT OF COAL BY RAIL

7.32. British Rail has traditionally been an important carrier of coal to generating stations, with road, canal and sea transport canals being alternatives. During the 1960s under 40 million tonnes a year were carried by rail, but in the 1970s this has increased and is estimated to have been 62 million in 1980. One important reason for this growth has been the innovation by BR in the mid 1960s of the 'Merry-Go-Round' (MGR) trains. These are trains which carry coal in wagons specially constructed for easy loading and unloading without stopping. They require purpose-built facilities at collieries and power stations. Because of their design, they require considerably fewer resources in terms of land, equipment and manpower than conventional train operation. Although proposed by BR, the MGR operation was developed jointly by BR, the CEGB and the NCB. Initially the system was devised for power stations but is now used at the Immingham export terminal and for other industrial coal.

7.33. The importance to BR of coal transport, and the CEGB's business in particular, is shown in the following table:

TABLE 7.5 **The relative importance of coal in BR freight business (million tonnes)**

Year	*CEGB coal*		*Coal for others*	*Total freight*	*CEGB coal as proportion of freight (%)*
	*MGR**	*Non-MGR*			
1976	44·8	10·2	40·4	176·0	31
1977	42·8	11·8	37·8	170·0	32
1978	47·6	9·1	35·8	171·0	33
1979	48·6	8·9	34·3	169·3	34

Source: British Rail

BR revenue from carrying coal for the CEGB was £116 million in 1979.
*Merry-Go-Round train.

The agreement with BR

7.34. Prior to 1976 the CEGB had a number of local agreements with BR for the transport of coal, and two national agreements which dealt with the use of conventional wagons and MGR trains respectively. Rates for MGR trains were lower and were intended to encourage the CEGB to invest in the necessary handling facilities. The rate structure for MGR trains was tapered after 30 miles, and this was a factor which encouraged the CEGB to locate some power stations away from the central coalfields. Price variation clauses based on the Wholesale Price Index were a feature of the agreements. By 1974 it had become apparent to BR that the agreements no longer brought in sufficient revenue to cover costs, and this together with the fixing of a financial target for the BR freight operations following the Railways Act 1974 led to the extensive revision contained in the present agreement.

7.35. Five features of the agreement were of interest to us:

(i) its duration;

(ii) the review periods;

(iii) exclusive dealing;

(iv) the rate structure; and

(v) the price variation mechanism.

It also contains clauses dealing with the detailed workings described in paragraphs 7.6 to 7.8, and the conversion of power stations to MGR operation. (Typically this costs about £3 million per station.)

The duration of the agreement, and review periods

7.36. The agreement came into operation on 1 January 1976 and is intended to last for 15 years. BR has told us that this was a compromise; it would have preferred ten years, which was about the time needed to recover its investment in wagons, whereas the CEGB wanted a longer time. As part of the compromise it was agreed to have two reviews of its operation, one in January 1981 and the other in January 1986.

The exclusive dealing arrangement

7.37. A prominent feature of the arrangement is the undertaking given by the CEGB, except for emergencies and with limited exclusions, to 'forego the use of road transport for coal supplies from rail connected sources to rail connected power stations . . .' BR has explained to us that because of its investment in MGR trains it would have preferred to agree a specific volume of business, as is normal in its other long-term contracts, but the CEGB felt unable to accept this either in total or for nominated power stations. In BR's view it had to accept the next best arrangement which was the exclusive right to carry such coal as the CEGB wished to use at the power stations covered by the clause. The CEGB judged that the additional costs it might incur by accepting this clause were more than offset by the reduction in the rates for carriage by rail.

The rate structure

7.38. As in the earlier agreements the present rate scales distinguish between MGR and non-MGR trains. Under the old and the new scales, for MGR and non-MGR trains, the minimum charging distance is four miles. In the earlier MGR scales the rate per tonne tapered between 30 and 60 miles with a further taper after 60 miles. This latter was eliminated in the 1 January 1976 scales. There is no taper for non-MGR trains. The scales at 1 April 1980 were as shown in Figure 7.1.

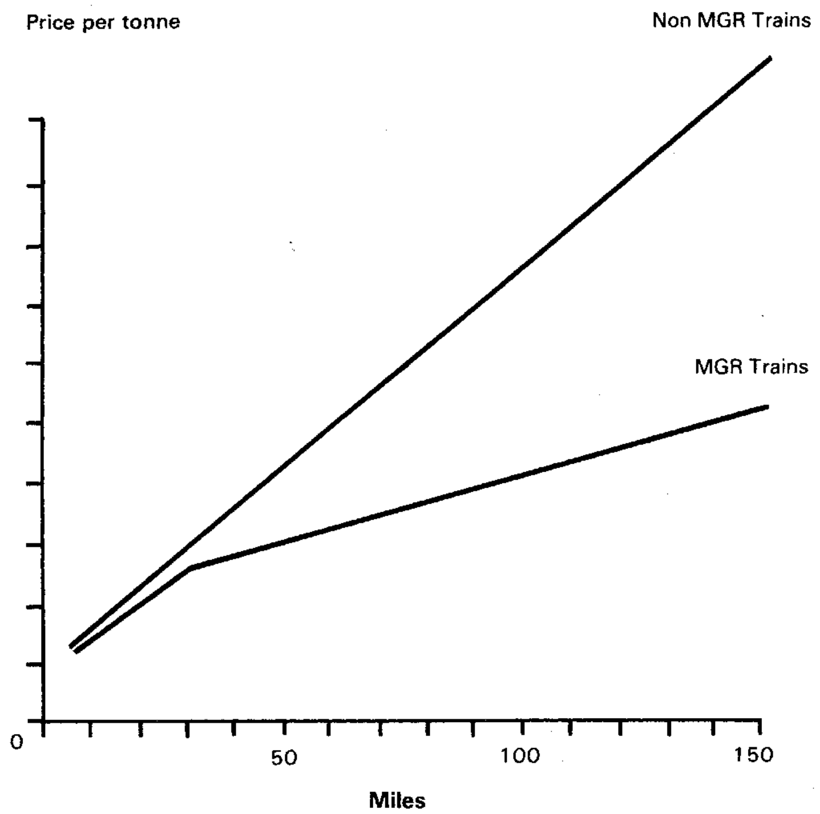
7.39. We asked BR about the relationship between the rate structure and its costs for journeys of differing distances. It has stated that there is no relationship with actual journey-related costs, as these can vary with geographical features and train formations etc. The rate structure was designed as a simple and easily understood method of raising the total revenue estimated to be needed to meet the costs of the CEGB coal business. As BR cannot yet allocate certain joint costs to classes of rail users it is not able to assess the true profitability of the freight business. Within the freight business it does not use more limited measures of profitability, such as contribution to overheads, to assess the value to it of the CEGB's coal business. Instead BR monitors the gross revenue received against a budget.

The price variation clause

7.40. The agreement provides for the rates to be adjusted in April and October each year according to movements in a weighted average of the Index of Basic Hourly Wage Rates of Manual Workers and the Index of Wholesale

FIGURE 7.1

BR Rates for Transporting Coal for CEGB 1 April 1980



Source: BR

Note. BR has told us that the average distance for MGR trains is 25 miles and for non-MGR trains 20 miles.

Prices. Because BR could not then allocate infrastructure costs between passenger and freight businesses, the CEGB stipulated that increases be restricted to 90 per cent of the figure calculated from the formula. About half of BR's freight business is covered by contracts which incorporate price variation clauses; their composition varies with commercial conditions.

7.41. We have asked BR why it chose this particular price variation mechanism rather than one based on movements in its own costs. It has stated that its primary objective was to preserve the real value of the business over a long period, and these two indices seemed to offer the best scope for doing so. In the long run changes in its own wage costs were likely to be at least of the same order of magnitude as the chosen wage index, and the Wholesale Price Index would reflect movements in other BR costs. The CEGB has told us that up to April 1980 the operation of the price variation mechanism has resulted in rates rising less than the Retail Price Index.

The monopoly position of BR for the transport of coal

7.42. To arrive at a fuller appreciation of this agreement we have sought to establish whether BR is for practical purposes a monopoly supplier of transport for coal. Although the CEGB owns and charters ships to carry coal to power stations in its South East Region, it has to use land transport for most of its inland power stations. It has told us that about 75 per cent of its coal is moved by rail, and it considers there would be formidable environmental and other problems in finding alternatives on a scale which would significantly reduce BR's relative importance. At present about 10 million tonnes a year are transported by road mostly over distances up to about 20 miles. In the short run it would not be possible to increase that amount substantially because capacity is not available. On the other hand, if not restricted by planning consent and other controls and if the CEGB entered into long-term contractual arrangements with road hauliers, it might be possible over a period of five years to move a further 5 million tonnes a year. However, this would place considerable strain on the roads and on the environment because the carrying capacity of a lorry is only perhaps 20 tonnes compared with 1,000 tonnes for a train. The CEGB also told us that assurances given by it at the planning stage of some power stations, and subsequent statutory consents, preclude the use of road transport to those stations.

7.43. BR has told us that it does not regard itself as totally free from competition in the transport of coal for the CEGB. It pointed out that the CEGB made other arrangements to carry about 25 per cent of its coal requirements, amounting to about 20 million tonnes a year and had gained considerable experience of using the alternatives of road and sea transport, canals and conveyors from collieries. Thus it was able to bargain effectively over rates. BR pointed out that rail transport has advantages over road; for example, an MGR train can carry as much as 50 lorries, and road hauliers lacked the national flexibility provided by the rail system. Although MGR trains are an efficient means of bulk transport, BR states that at times road transport is offered to power station managers at lower rates. The CEGB maintains that only non-rail connected sources of coal are involved.

Issues raised by the agreement with BR

7.44. Two main issues arise from the present agreement, and in discussing them we would stress they have to be judged in the context that the arrangements were intended to last for 15 years, and both industries have some power to influence the prices and terms and conditions for the transport of coal by rail: BR as the preponderant carrier, and the CEGB as the preponderant buyer.

7.45. The first issue arises from the exclusive dealing arrangement under which BR has the right to carry all coal from rail connected sources to rail connected power stations. A relevant question is whether the restriction in the agreement on competition from other transport is likely to result in the CEGB's costs being higher. BR has told us that at present competitive offers of road transport are sometimes made, so the restriction must have this effect even if the effect is very small. It is difficult to judge what the effect might be in the long term. The CEGB has indicated there is scope for increasing the share of road transport, but to what extent it would be acceptable on environmental and other grounds is something on which we can form no view.

7.46. The second issue is whether the present rate scale and price variation mechanism have adverse effects on the CEGB's costs. In Chapter 6 we have described the CEGB's computer-based system for minimising the costs to it of transporting coal, subject to other relevant constraints. What the CEGB does is to minimise the total of the charges arising from the rate structure. As BR has told us (see paragraph 7.39) that there is no relationship between the charges and journey costs there must be a possibility that BR does not minimise its own costs to the extent that it might if there were a direct relationship. Because we have not investigated the structure of BR's costs for transporting coal we cannot reach a conclusion, but if costs are not minimised, then it follows that for any given financial target for BR's freight business the level of charges to the CEGB would be correspondingly higher.

7.47. It may also be the case that the price variation mechanism results in the CEGB's costs being higher than they would be if there were different arrangements for adjusting charges. At present the rate scale is adjusted on the basis of changes in indices which measure national economic aggregates. There is no direct or necessary relationship between these and BR's costs. If BR's costs showed a tendency to rise faster than the indices then the mechanism would act as a constraint on upward movement in the rate scale, but whether this would be an unambiguous benefit over a 15 year period would depend upon the scope for cost reductions in BR's coal and other freight business. If BR does improve productivity so that its costs rise less than the indices then under the arrangements none of the benefits would be passed on to the CEGB and electricity users; they would be retained by BR. In these circumstances it is also possible that BR's determination to achieve such productivity improvements might be impaired with the further consequence that costs in the freight business are higher than justified by the potential for improved productivity.

Other fuel supplies

Natural gas

7.48. The CEGB buys gas from the British Gas Corporation under contracts which provide for annual price reviews. The CEGB's purchases have dwindled from nearly 4 mtce in 1975 and are unlikely to exceed 0·5 million mtce from now onwards.

Oil

7.49. The CEGB buys different oils for four principal purposes: 'main burn' oil used in oil-fired generating stations, 'light-up' oil for controlling the flame at coal-fired stations, gas oil for the gas turbines and diesel oil for use by bulldozers, vehicles etc. The last three are usually grouped under the heading of miscellaneous oils. In purchasing the CEGB places paramount importance on security of supply, and in choosing between tenderers takes into account location, the supplier's relationship with other customers, capacity and exchange relationships (with other oil companies) and financial position where relevant.

MAIN BURN OIL

7.50. The CEGB's strategy has been to site oil-fired stations next to refineries so as to take advantage of ex-refinery prices, and to minimise transport costs. However, it has also taken care, with the exception of Fawley, to have more than one supplier for each station so as to have some countervailing power. In the case of Fawley, the CEGB does not believe that the oil company has been able to take advantage of being the single supplier.

7.51. Each contract with an oil supplier stipulates an initial starting price, a variation mechanism related to the landed cost of crude oil in sterling, and an annual review. The review dates have been staggered by the CEGB to put it in a better bargaining position. At present, the crude oil market is in such disarray that the variation mechanisms have been suspended and prices are negotiated quarterly. The CEGB believes that this results in competitive prices because it is a skilled buyer with good market intelligence.

7.52. Contracts for main burn oil generally contain clauses stipulating maximum and minimum quantities to be supplied during the year. These normally operated within the framework of price negotiations, and gave protection to the CEGB in times of short supply, and protection, through the minimum, to the oil companies. Until 1980 the minimum quantity clauses gave the CEGB no problems because requirements always exceeded those amounts; now, however, the oil 'burn' has been reduced so much that the CEGB is engaged in negotiations over the contracted minimum quantities.

7.53. Until the summer of 1979 the CEGB bought oil on the spot market to supplement its normal contracts. The amounts purchased varied from year to year with the maximum being 1·5 million tonnes, about 10 to 18 per cent of its total oil purchase, and the CEGB mainly bought in the summer when prices were lower. In 1980 it has not bought any oil on the spot market.

MISCELLANEOUS OILS

7.54. There are no special CEGB quality requirements for these oils, and it buys the same commercial grades as other users. About 1·5 million tonnes are purchased annually from a large number of suppliers. As with main burn oil security of supply is a primary requirement and contracts are put out to tender with approved suppliers only. Most contracts are for three years, and some are for five; the CEGB has staggered them so that each year about a third of them are due for renewal. The prices include delivery to the CEGB and are expressed as discounts off the tenderers' list prices. As with main burn oil the contracts provide for an annual review. There are no maximum or minimum requirements. The CEGB is free to take any quantities it requires, and there are no price variation clauses. Although prices are expressed as discounts off list prices, the CEGB has the right to go back to suppliers if it considers prices to be excessive. The CEGB believes that the prices it pays are competitively determined.

Nuclear fuel

7.55. To understand the special options open for nuclear fuel management compared with fossil fuels some understanding of the principles of nuclear generation is necessary. Appendix 17 outlines in a very simplified form, for the non-technical reader, the principles which lead to 'thermal' and 'fast' reactor types, the need for enrichment of natural uranium in fissionable material and the concept of the fuel cycle and nuclear waste management. This part of the chapter will discuss the CEGB's policy with respect to nuclear fuel procurement and management assuming familiarity with the nuclear principles, under the following headings:

—procurement of supplies of natural uranium;

—enrichment of natural uranium;

—fabrication of fuel elements;

—reprocessing of irradiated fuel;

—plutonium policy.

7.56. Table 7.6 sets out the current annual costs of the components of the fuel cycle for the Board's Magnox and AGR reactors. It should be noted that AGR fuel is not currently being reprocessed.

TABLE 7.6 **Relative annual cost of nuclear fuel cycle components**

	Current annual expenditure in £m	**Part of Magnox cycle*	**Part of AGR cycle*	**Needed for PWR cycle*
Supplies of natural uranium	44·50	*	*	*
Conversion to uranium hexafluoride	3·00	—	*	*
Uranium enrichment	22·50	—	*	*
Fuel fabrication	36·25	*	*	*
Reprocessing	80·00	*	*	*
Disposal of wastes	2·00	*	*	*
Recycling of uranium	30·00	*	*	*
Plutonium extraction and storage	8·25	*	*	*

Source: The CEGB

Procurement of Natural Uranium

HISTORICAL BACKGROUND

7.57. Uranium ore concentrate for the United Kingdom was procured by the Atomic Energy Authority until 1974, then by British Nuclear Fuels Limited until 1979 and from that date has been procured by 'The British Civil Uranium Procurement Directorate' (BCUPD), which is a purchasing group comprising the CEGB, SSEB and BNFL. BCUPD has no legal status and the CEGB enters into supplies contracts for the group as a whole. There are no formal agreements between the participating parties.

7.58. The United Kingdom has always purchased uranium by means of long-term contracts of between five and ten years' duration, negotiated many years in advance.

SECURITY OF SUPPLIES

7.59. No commercial indigenous supplies of suitable uranium ores have been discovered in the United Kingdom. Security of supply is therefore important for a continuous programme of nuclear power. The CEGB attempts to ensure a sufficient degree of security by the following methods:

- —geographical and political diversification;
- —contracts over-lapping in time;
- —direct involvement in mining equity,

as well as by recycling depleted uranium. The Board's current policy is to provide 75 per cent of its needs through long term contracts with suppliers and 25 per cent through direct involvement in mining.

LONG-TERM CONTRACTS

7.60. United Kingdom civil supplies come from Canada and Namibia; political considerations have up to now excluded obtaining supplies from South Africa.

[*Details omitted.*
See note on page iv.]

PRICE NEGOTIATION

7.61. There are few suppliers and users of uranium. Contract prices depend on the timing of payments, the size and duration of the contract and the operation of price clauses. Utilities and suppliers regard the prices they pay for supplies as a commercial secret; it is therefore very difficult to discover a forward market price.

[*Paragraphs 7.62 to 7.64 omitted.*
See note on page iv.]

PREDICTION OF FUTURE PRICES

7.65. The CEGB has not yet developed any formal models for predicting future prices. Instead the Board estimates the rate of commissioning of world nuclear plant and the rate of development of new mines to establish the future demand and supply situation, from which it derives possible effects on prices. The dominant disturbance factor is probably intervention by governments. It should be borne in mind that when considering future purchases the CEGB always has a choice between buying fresh supplies or subjecting depleted uranium to the enrichment process.

DIRECT INVOLVEMENT IN MINING EQUITY

7.66. The BCUPD has set up a geological exploration team to advise on and assist in the search for uranium ores in several parts of the world. The work is carried out through joint ventures with mining companies in Canada and Australia, USA and elsewhere. The CEGB's contribution to this geological work costs about £1 million a year.

7.67. As a result of these activities some deposits of high grade ores have been discovered, but not in commercial quantities. The Board has no predetermined policy with respect to the options available in the event of discovering commercially exploitable ores. It might develop them or sell its interest.

7.68. On behalf of BCUPD the Board has examined the possibility of securing an interest in several mining projects, especially the Australian Ranger mine. This venture did not mature, partly because the Board could not obtain guaranteed access to supplies, and there was uncertainty about the future valuation of the assets. It believes that the cost of acquiring a medium-sized mine would be of the order of £100 million.

PROCUREMENT PERFORMANCE

7.69. We have examined the trend in the delivered price of uranium to the CEGB since 1973, compared with spot market prices over the same period. We are satisfied that the Board has been obtaining good contract prices. [*Details omitted. See note on page iv.*]

URANIUM STOCKING POLICY

7.70. Stockholding requirements can be predicted for a given forward reactor programme. The important factors are: the rate of reactor commissioning, the initial charge of fuel, the level of working stocks for fabrication and recycling at BNFL, the volume of depleted material recycled, the level of strategic stocks and the lead time for fresh supplies, and the fuel utilisation per charge.

7.71. The lead time for developing new supplies can be 15 years or more and contracts must be made well in advance of reactor starts.

[*Details omitted.
See note on page iv.*]

7.72. The CEGB's present policy, once there is adequate diversity of supplies, is to hold the equivalent of two years' supply of natural uranium including the equivalent of eight months' supply of enriched material. Since neither of these materials represent toxic or radiological hazards, the cost of providing storage facilities and hence the cost of holding stocks is relatively low.

7.73.

[*Details omitted.
See note on page iv.*]

ENRICHMENT OF NATURAL URANIUM

7.74. The Board currently requires uranium enriched in the isotope U235 for its AGR fuel and also for any future PWR station. The normal procedure is for the client to provide the uranium base material and for the processor to process it into two fractions, depleted and enriched, which are returned to the client.

7.75. Until 1978 the CEGB obtained enriched material from the UKAEA's diffusion plant at Capenhurst. This plant was refurbished in 1966 to provide material for the AGR programme and is still available to upgrade depleted uranium to the natural uranium equivalent. The Board has told us that it proposes to discontinue the use of this facility as soon as possible in view of its high production costs and the Board's present stock levels.

FIGURE 7.2

[Details omitted.
See note on page iv.]

7.76. In 1971 Britain, the Netherlands and West Germany agreed to co-operate in the development of the centrifuge method of enrichment. This process should offer substantial cost advantages over the diffusion method, because of the smaller electrical energy requirement. Two plants are operating, one at Capenhurst, the other at Almelo (the Netherlands). Additional plants are under construction at both sites and there is a proposal to build a plant in the Federal Republic. Equity shareholdings in the company, URENCO, are shown in Table 7.8.

TABLE 7·8 **Equity shareholdings in URENCO companies**

	URENCO (UK)	*URENCO (Nederland)*	*URENCO (Deutschland)*
BNFL	96%	2%	2%
UCN	2%	96%	2%
URANIT (West Germany)	2%	2%	96%

Source: The CEGB.

7.77 The CEGB agreed in principle to procure the bulk of its enrichment services from URENCO. Two contracts have been placed for 5,950 tonnes separative work for the period 1980–94 representing 70 per cent of the CEGB's estimated requirements over the period.

7.78 URENCO undertook construction of the centrifuge plants against guaranteed orders and an advance by the CEGB of some of the capital cost which is deductible from payments for initial supplies. The advances against contracts are given in Table 7.9.

TABLE 7.9 **Advance payments made to URENCO under terms of contract**

	Payment already made	*To be made in 1981*	*To be made in 1982*
1976 contract	£7·144m	—	—
1977 contract	£10·676m	£4·5m	£4·0m

Source: The CEGB

URENCO PRICE NEGOTIATIONS

7.79. The URENCO contract allows for price escalation on the basis of defined indices which can be checked against external information. In addition, either party can request a price review if the escalated contract price differs by more than an agreed threshold from average world market price.

7.80. In the original contract the agreed threshold for triggering a review was a 5 per cent variation from world market price. For enrichment there is less difficulty in establishing a market price since there are alternative suppliers to URENCO in the USA, in the USSR and in France. The current market price is based mainly on prices charged in the USA for the large volume of supplies from their diffusion plants. Information on these prices is freely available.

7.81. The CEGB has recently invoked the review clause in an attempt to procure a reduction in URENCO's price. URENCO claims that the reduction sought would bring the current price below cost. It was agreed to alter the threshold for triggering a price review to accomodate a larger variation from world market prices. This has had the effect of preventing the Board from obtaining an immediate reduction. However, an examination of comparative production cost estimates from the centrifuge and diffusion processes suggests that the centrifuge process will be substantially cheaper in the longer run. The energy costs of the diffusion process will rise more steeply, and in consequence the price quoted on the American market is likely to be substantially higher than the cost-escalated URENCO price. Under the original contract URENCO would have been able to review its prices upwards towards the diffusion price; this is now prevented unless the difference is very substantial.

7.82. As additional security in the early stages of the URENCO development the Board, acting also on behalf of SSEB, has negotiated a contract for 1,000 tonnes separative enrichment work in the USSR over the period 1980–90 (of which the CEGB's share is 72 per cent and SSEB's is 28 per cent). The Board has told us that price negotiations were difficult because of lack of cost information on Russian production. However, it believes that the settlement price was effectively about 4 per cent below that quoted by the USA, since the agreement was to accept the price of the most favourable US source but without making advance payments.

ENRICHED URANIUM STOCKS

7.83. The Board's policy is to hold the equivalent of eight months supply of enriched material. However, because of the delays to the nuclear programme the Board's stocks of enriched material will be in excess of the optimum. The Board estimates that it will hold £36 million of stock at 31 March 1981 and £70 million at 31 March 1982, representing about 18 months' and two years' consumption respectively. The Board has told us that it is attempting to bring stocks more into line with existing needs by rescheduling deliveries from both URENCO and USSR.

The Rest of the Fuel Cycle

RELATIONSHIP WITH BNFL

7.84. With the exception of the supply of natural uranium and its enrichment the CEGB obtains all other nuclear fuel services from British Nuclear Fuels Limited under a Terms of Trading Agreement signed on 16 May 1973 and effective from 1 April 1971 to 31 March 1983. Previous to this the SSEB and the CEGB had negotiated separate contracts and terms of trading with the United Kingdom Atomic Energy Authority for Magnox fuel, AGR fuel and enrichment. The fuel contracts included provision for reprocessing irradiated fuel. The existing contracts were transferred to BNFL on 1 April 1971. The present agreement covers the terms of trading between BNFL, the CEGB and SSEB. A summary of the current basis of trading is set out below:

(*a*) The CEGB and SSEB underwrite the costs of specific plant used by BNFL for the provision of nuclear fuel services to the Boards. This includes:

—conversion to uranium hexafluoride;
—uranium enrichment;
—fuel fabrication;
—irradiated fuel reprocessing;
—plutonium separation;
—waste management.

(*b*) There is provision for detailed consultation on BNFL's pricing procedures, including an analysis of price variations.

(*c*) There is consultation on the scope and timing of major capital projects, including regular progress reports during construction.

(*d*) There is provision for the CEGB and SSEB to pay BNFL an agreed return subject to BNFL meeting agreed production and cost targets, and to share in any shortfall or excess earned by BNFL. However, BNFL is required to take a degree of commercial risk. The settlement with respect to BNFL's return on investment (ROI) is made annually (see paragraph 7.92).

(*e*) There is provision for the CEGB and SSEB to share in any profits arising from sales to outside organisations.

7.85. The services provided to the CEGB and SSEB currently represent about 60 per cent of BNFL's turnover of about £360 million a year, and provide 80 per cent of the trading profit. The exclusive contract for services for Magnox and AGR fuels was necessary because no foreign supplier thought it worthwhile to lay down capital to supply the unique United Kingdom fuel. However, the PWR programme may introduce the possibility of competitive supply tenders from foreign processors.

7.86. The CEGB has told us that it obtains from BNFL a large volume of current cost and profit data, with which it is satisfied.

7.87. A major concern of both parties has been the consequences of the United Kingdom Government's dividends guidelines which require that BNFL should aim to pay dividends commensurate with those achieved in comparable sectors of United Kingdom industry. BNFL has sought to fix prices on the basis of full cost reimbursement plus an additional margin to meet the required rate of return. The CEGB wants to see BNFL bearing some of the commercial risks and having an incentive to maintain efficiency and improve performance, and its objective has been to influence the subsequent trading agreements in this direction.

BASIC PRICE PROCEDURE

7.88. The 1967 agreement covering the supply of Magnox fuel elements sets out the basic price mechanism as a recovery of costs plus a trading surplus for UKAEA at a rate to be agreed. At that time there were no official government targets: the UKAEA wanted a return over the Treasury rate of interest to finance its needs for fixed and working capital over the following five years, but the CEGB felt that the rate of return should be no more than that required of the CEGB. The final agreement did not allow for a specific rate but for a total return of £2 million over the five years, reviewable after three years. This was superseded in 1968 by a directive from the Minister of Technology requiring the Authority to earn a trading surplus sufficient to meet the Government's financial targets with provision for sharing any additional surplus or shortfall.

7.89. In the 1970 AGR fuel contract the pricing mechanism was again in terms of cost reimbursement plus a trading surplus sufficient to meet the Government's financial targets with provision for sharing additional surplus or shortfall. The target rate of return was per cent, and any excess between and per cent was to be shared equally between the Authority and the Generating Boards (the CEGB and the SSEB). Any excess above per cent was to be returned to the Boards in reduced prices and any shortfall below per cent would be recovered in increased prices. [*Figures omitted. See note on page iv.*]

7.90. When the trading agreement with BNFL was negotiated in 1973, the targets and distribution of excess or shortfall on return on investment were transferred from the original fuel supply agreements. Capital employed was averaged over three year periods for the calculation of ROI and the target rate was reviewable for each three year period. The terms of trading (1973) make provision for sharing any profit over £10,000, resulting from overseas trading.

7.91. A provision was also envisaged for developing a performance monitoring scheme to assess the efficiency of BNFL management. The share of any ROI shortfall borne by the Generating Boards would be dependent on the degree of achievement by BNFL of a standard performance. The parties were unable to agree a scheme and the proposal was superseded by the variable margin device discussed below which was intended as a reward or penalty depending on BNFL's performance against agreed throughputs.

7.92. The terms of trading were revised in 1977, when the following changes were introduced:

(*a*) The target ROI was set at per cent. In the event that an excess between per cent and per cent occurred this would accrue to BNFL, or that a shortfall occurred between per cent and per cent this would be borne solely by BNFL. Any excess above per cent or shortfall below per cent would be shared equally between BNFL and the Boards. [*Figures omitted. See note on page iv.*]

(*b*) Settlements in respect of ROI earnings would be made annually instead of triennially as previously.

(*c*) The provisions under which BNFL was allowed to adjust prices retrospectively were changed so that BNFL would be at risk in respect of shortfalls in throughput resulting from circumstances defined as being within BNFL's control.

(*d*) BNFL would in future carry the financial risk associated with the 'good workmanship' guarantee of the fuel; previously any costs in this respect had been recoverable from the Generating Boards.

7.93. Following the 1980 review, amendment of the 1977 agreement included the following adjustments:

(*a*) The sum payable by the Generating Boards in respect of the target return on capital employed will in future be abated by an allocation, pro rata to usage, to all other full cost users of the 'Home Capacity Plant' with the exception of BNFL's use for fuelling services provided for its own reactors at Calder Hall and Chapelcross.

(*b*) The total capital employed will be divided into two categories—'capital associated with plants in course of construction' and 'all other capital employed'. Capital in the fomer category will earn a lower rate of returns.

(*c*) The Generating Boards will obtain a greater share of profits arising from BNFL's overseas trading.

PRICE VARIATIONS

7.94. The base price in the Magnox and AGR contracts is determined by the principle of full cost recovery, ie design, manufacture and supply, plus ROI. Price variations are allowed as follows:

(i) for modifications of design of fuel agreed between the parties;

(ii) for changes in delivered volume from the agreed volumes if requested by the Generating Boards or resulting from defined circumstances considered to be outside BNFL's reasonable control;

(iii) escalation based on agreed published indices;

(iv) change in enrichment (AGR contract only);

(v) changes in costs of components, depreciation and agreed R & D programmes; and

(vi) changes in the average capital employed.

FABRICATION OF FUEL

7.95. The CEGB is generally very satisfied with BNFL's performance on both Magnox and AGR fuel, although there has been a dispute about the quality of certain AGR fuel elements.

REPROCESSING OF IRRADIATED FUEL

Magnox fuel

7.96. Although the most convenient way of storing irradiated Magnox fuel is in water-filled storage ponds it cannot be stored for many years in this way because the Magnox canning material corrodes. The fuel must therefore be reprocessed and the fission products and transuranic elements extracted. BNFL reprocessing costs have risen steeply since 1975 and its projections suggest further increases in real terms over the next decade (see Table 7.10).

TABLE 7.10 **Trend in Magnox reprocessing costs**

Year	*Irradiated Magnox reprocessing cost index per unit 1975 prices as 100*
1975	100
1977	159
1980	299
1983	598
1987	1,055
1990	562

Source: Monopolies Commission Study

7.97. In the mid 1970s it was recognised that additional plant capacity at BNFL would be required to process Magnox fuel when the programme is running at its peak. Three factors influenced the size of that investment:

(i) plant can be installed only in discrete capacities;

(ii) the designed throughput rate of the original plant was achieved only for short periods; and

(iii) the continuing requirement to meet new safety and environmental standards.

7.98. BNFL's proposed investment plans represent a total of £1,200 million at 1980 prices, on a set of construction projects over different timescales. Some of the plants will not be fully depreciated until the early years of the next century. The Board has estimated the effect of this expenditure over time against a standard discount rate (see paragraph 5.9) and believes that it will increase the cost of nuclear generation by about 0·36 p/kWh (1980 money values); to put this in perspective, the inclusive fuel costs of Magnox stations in 1979–80 were 0·60 pence/kWh (in 1979–80 money values).

7.99. The CEGB has been concerned about the cost effects of this level of investment and has been in discussion with BNFL to ensure that the investment will match the rundown of the Magnox programme without leaving substantial assets unused at the end of the period. Valuation of the Magnox investment is made somewhat more difficult since some of the new plant and services will be used on the AGR reprocessing programme.

7.100. The provisional result of the review suggests that a reduction of about £300 million will be possible, but the precise apportionment of the final sum between Magnox and AGR is still to be agreed. If the earlier estimate of £1,200 million is reduced, and it proves possible to allocate part of the cost to AGR fuel processing, then the increase in Magnox generation costs (see paragraph 7.98) will be less.

AGR (oxide) fuel

7.101. The uranium dioxide AGR fuel is canned in stainless steel which is resistant to corrosion both in air and in water. The long-term stability of the fuel provides two options for the management of irradiated fuel:

(*a*) short-term storage in water and reprocessing to extract the fission products and recycle, or

(*b*) long-term dry storage of the irradiated fuel assembly followed eventually by reprocessing.

7.102. BNFL's proposals for a thermal oxide reprocessing plant (THORP) were approved by the Government after the 1977 Windscale Inquiry. The current estimate of capital cost is about £800 million leading to a processing cost of about £260,000 per unit for reprocessing 6,000 tons over the 10 year period starting 1987. These are not detailed estimates but a revaluation of the outline costs made by BNFL for the Windscale inquiry.

7.103. In view of the cost escalation experienced between initial and final costings of the refurbishing of the Magnox reprocessing plant the CEGB is pressing BNFL for early detailed design costings. However, the detailed design requires specialist chemical engineering skills which are scarce. More detailed cost estimates will not be available before 1982.

7.104. BNFL has told us that a number of events have made planning of the oxide processing difficult. First, an unforeseen technical problem with the original pilot header plant resulted in redesign and a period of plant outage. Secondly, because of changes in projected world nuclear capacity the two processing lines originally proposed have had to be redesigned as a single line.

7.105. However BNFL does not expect the same escalation in detailed costings as occurred in the Magnox programme, first, because it has the Magnox experience to build upon and secondly, because in the current design work it has provided for expected changes in safety standards.

7.106. The CEGB is being pressed by BNFL to enter into a contract in the near future for reprocessing 2,000 tons of oxide fuel in THORP. BNFL has already concluded contracts with European and Japanese utilities for oxide reprocessing and wishes to plan for an integrated total capacity.

7.107. The Board has told us that in the AGR investment appraisal made in the 1960s it had been assumed that oxide fuel would be stored temporarily before reprocessing. There is now no reprocessing plant available and the plant which is to be constructed at Windscale will not be completed in time. In the meantime the AGR station at Hinkley Point B is operating and its fuel has to be stored. The Board is now reappraising its strategy for irradiated oxide fuel; its re-evaluation will include estimation of the cost of long-term dry storage.

Plutonium recovery

7.108. The CEGB has told us that it has no firm plans for a fast breeder programme, principally because there is sufficient uranium to fuel thermal reactors until the end of the century. Furthermore it does not believe that a commercially viable FBR design has been demonstrated. It expects that the development of a safe and commercially viable FBR is most likely to result from an international programme. The advantages of fuel supply security and fuel economy provided by a self-fuelling nuclear cycle are evident, and the CEGB is separating and stockpiling plutonium against the time when such a system becomes viable.

7.109. The Magnox programme will generate sufficient plutonium by 2000 to fuel the first stage of an FBR programme. The AGR fuel will provide only a small additional quantity of plutonium, and its recovery, through reprocessing, is not critical to a decision on a future FBR programme.

7.110. The CEGB is attempting to take commercial advantage of its plutonium stocks by leasing to other users. The Board currently has an income of about £2 million a year from leasing plutonium.

Conclusions

Coal and its transport

7.111. The terms of our reference require us to look at the effect of the CEGB's purchasing policies on its costs and on the public interest. As we have pointed out coal is the main item of its costs. It is clear that the CEGB has developed an intricate and flexible system for purchasing and transporting coal which helps to minimise its costs within the constraints set by the arrangements with the NCB and BR. Thus the CEGB has potentially two related ways of reducing its costs. First, it can seek cheaper sources of coal and transport, and secondly, it can seek to ensure that the NCB and BR operate as efficiently as possible, and that the benefits of this efficiency are passed on to the CEGB in the form of lower prices.

7.112. In the recent past the only major source of cheaper coal has been imports, and mainly for reasons of Government policy the CEGB has been unable to take full advantage of such opportunities as were available. In our view this has had the effect of raising the CEGB's costs because of the extent to which it has had to use more expensive home-produced coal. However, barriers to imported coal could have even more important consequences in the future. We have shown in paragraphs 5.39 and 5.40 that there are well founded expectations that world trade in coal will develop rapidly, and electric utilities in participation with coal producers may be a major force in promoting this growth. In the 1980–81 Development Review (see Chapter 5), the CEGB assumed that the price of imported coal will be 40 per cent higher than home produced coal by the end of the century. For the reasons given in paragraph 5.141 we question the validity of this assumption and consider that unless the CEGB's capacity to import can be increased, the consumer is likely to be faced with an even faster rate of increase in electricity prices. Oil prices now that they are rising rapidly do not act as a restraint on the price of home-produced coal. We recognise the social and industrial difficulties which might arise from any policy of substituting imported coal for domestically produced coal; nevertheless, simply from the narrow standpoint of its own efficiency and costs, it would be desirable for the CEGB to consider its strategy for coal imports. We welcome the statement in the CEGB's Annual

Report 1979–80 that it planned a modest increase in its coal imports for 1980–81 and is keeping under review the scope for increasing coal importing facilities.

7.113. On the question of whether the CEGB is able to influence the NCB's efficiency, the Board has argued that the existing coal pricing structure does not give the NCB much incentive to close uneconomic pits, and this has led to higher electricity prices than might otherwise be the case. It has also said that the failure of the NCB to disclose sufficient information on costs makes it uncertain as to the extent of cross-subsidiation of pits, and on the possible subsidisation by it of other industrial coal purchasers. Without an analysis of the NCB's costs, prices, and closure policy it is difficult for us to come to any conclusions about these claims, or to indicate what might be a desirable price structure for steam coal.

7.114. The understanding between the CEGB and the NCB is to be welcomed as a recognition of mutual dependence which may help to improve relations between the two boards and contribute to improved planning. However, in our view the understanding has objectionable features. First, it envisages coal prices being raised by reference to an index rather than being related to changes in the costs of the supplying industry, or to long-run marginal costs. Secondly, it may induce the NCB, so as to keep its prices to the CEGB in line with the RPI, to raise more rapidly its prices to other customers which are less important to it. We recommend that the Board should seek to improve the terms and extend the duration of the understanding.

7.115. In paragraphs 7.44 to 7.47 we have set out the two main issues arising from the agreement with British Rail which we think are directly relevant to our consideration of the CEGB's efficiency and costs; they are the exclusive dealing clause, and the price variation mechanism. BR pressed for exclusive dealing as a second best when it was unable to get a commitment from the CEGB for a minimum quantity or value of business. Although a substantial change in the means of transporting coal could have serious environmental effects, in our view the clause is a major restriction on competition by alternative forms of transport, and we consider it inappropriate that two nationalised industries should have agreed upon it. We recommend that the restriction should be abandoned.

7.116. We also recommend that the two industries should revise the price variation mechanism. We can understand that having been unable to get a commitment from the CEGB for a minimum quantity or value of business BR should want a variation mechanism to preserve the real value of the traffic to it. However, we consider the present mechanism to be inappropriate for two reasons. First, it is an invitation to suppliers of goods and services including labour to BR to keep their prices up, broadly speaking, to the general level of inflation. Secondly, it does not explicitly provide for improvements in productivity in BR's coal business to be shared with the CEGB. We recommend that the price variation mechanism should be revised so as to give BR a greater inducement to limit growth of its costs and to enable the CEGB to benefit from improvements in productivity in rail carriage of coal.

Oil purchases

7.117. The CEGB is not in such a strong position as a buyer of oil as it is for coal, and therefore it is not able to exert much pressure on oil prices. We also believe that there is competition amongst the oil companies to supply the CEGB with oil. Although the CEGB has told us it is concerned that prices of heavy fuel oil in the United Kingdom are higher than on the Continent we have not investigated this claim. Our conclusions on prices relate to the CEGB's purchases in the United Kingdom. In its tendering and contractual relationships CEGB has generally succeeded in maintaining considerable flexibility, and we believe it is efficient and professional in its oil purchasing arrangements. However, certain of its main burn contracts contain restrictive minimum quantity clauses, but we understand that the parties are now negotiating the removal of these. They have had only a minor effect on costs.

Nuclear fuel

7.118. Given the initial Magnox programme the Board's first priority necessarily was to secure future supplies of uranium to ensure maximum contribution of the Magnox stations to the CEGB's base load. We are satisfied that the strategy of long-term forward contracts has been successful in meeting this priority and effective up to now in securing supplies at prices lower than those ruling on the spot market.

7.119. The contractual arrangements for the supply of uranium provide for the nuclear programme until the 1990s beyond which there may be a shortfall. Given the importance of securing supplies and the uncertainty of eventual capacity requirements we think that the Board has been prudent in the management of its present supply contracts and in its stockholding policy. However, we recommend that the Board should negotiate flexible 'call-off' clauses in new contracts in order to keep stock levels as close as possible to current requirements.

7.120. We recommend that the Board presses forward through BCUPD with its diversification policy both in terms of all geographic alternatives open to it and in terms of obtaining a direct interest. We believe that diversification will improve the Board's negotiating position.

7.121. If the projected nuclear programme is carried out, supplies of the necessary fuel after 1992 and the cost of electricity at that time will depend on the terms of new contracts which will have to be made.

7.122. The Board's current policy of procuring enrichment services from the centrifuge developments appears to be justified by the cost advantage inherent in the lower energy requirement of this process. It is important that the Board should share in this advantage and we note that it may have secured such gains in the medium term by negotiating the URENCO contract terms.

7.123. The relationship between the CEGB and BNFL is predominantly that of monopoly supplier and purchaser since the products and services are unique to the current United Kingdom reactors. The resulting trading relationship between two such publicly owned enterprises raises general issues which are discussed in Chapter 13. In this chapter we consider only the CEGB's management of that relationship. Since the CEGB underwrites so much of BNFL's capital we recommend that consideration should be given to the appointment of one or more representatives of the CEGB to the BNFL Board.

7.124. The terms of trading require BNFL to provide specified information on operating and investment costs. As regards operating costs, BNFL is doing what the terms of trading require and giving the CEGB satisfactory information. But as to investment costs, while there are no grounds for suggesting that the requirements of the terms of trading are not being met, nevertheless the position is that the CEGB has no more accurate information on the escalation of costs than has been described in paragraphs 7.103 and 7.104.

7.125. We find it surprising that, 16 years after the first order for an AGR, the Board has still not decided how to deal with the irradiated fuel. The Board has been slow in producing firm costing for the long-term dry storage option for irradiated AGR fuel and has not been supplied by BNFL with reliable cost estimates for reprocessing. This must have reduced the reliability of investment appraisal, and should be remedied.

7.126. Over the various reviews of the terms of trading we observe some signs of improvement tending towards a sounder commercial base, with incentives for efficient operation and a degree of commercial risk being taken by BNFL. We expect this trend to continue particularly if BNFL succeeds in realising larger foreign sales. We hope that the Board will continue to press for improvements in the terms of trading.

7.127. We emphasise the potentially harmful effects of price variation clauses which are not related to operational efficiency. We urge the two boards to resume the search for standard efficiency norms against which the manufacturing efficiency of BNFL could be measured. If BNFL increases its efficiency it should share the benefit with the CEGB and if this is achieved then it should be reflected in the negotiation of better margins for the CEGB.

7.128. We recommend that, should a PWR programme be undertaken, then the CEGB should continue its diversification policy and seek competitive tenders from both BNFL and foreign organisations for the supply and reprocessing of the fuel.

CHAPTER 8

Availability and maintenance

8.1. The availability of plant for the production of electricity is crucial to the operating efficiency and effectiveness of the CEGB. Plant cannot be available at all times because of the need for essential maintenance and obligatory statutory inspections. The pattern of operation for a station will be determined by its position in the Merit Order Schedule, which ranks each station's output according to its direct cost of production. All stations are expected to supply electricity according to the instructions of the Grid Control Centres and to the agreed operating regime (see Chapter 6). Low merit order plant may therefore be used for only a small proportion of its total potential availability, normally at peak demand times.

8.2. A power station's position in the merit order depends mostly on the delivered cost of heat and the thermal efficiency of the plant and hence factors outside the control of any power station can produce very marked changes in the ranking. The fluctuations in relative fossil fuel prices, especially oil, have been responsible for plant previously on 'base load' now working only to meet peak demands, and in some cases requiring two-shift rather than three-shift operation.

8.3. The importance of attention to maintenance so as to reduce 'outage'[1] can be demonstrated by the following figures which show typical outage costs for various types of plant, in terms of additional costs of generation by having to use other more costly plant.

Plant	*Typical plant outage cost per day*
500 MW/660 MW—Coal fired	£47,500
500 MW —Oil fired	£5,000
AGR 500 MW (interim rating) —Nuclear	£160,000

8.4. The deterioration of plant is controlled in the following ways:

(*a*) Routine Preventive Maintenance—which can normally be carried out while the plant is running.

(*b*) Planned Outage Maintenance—carried out when the plant is not running and therefore, in the case of high merit plant, expensive in terms of consequential outage costs. It thus pays to concentrate the work into the shortest possible time.

(*c*) Breakdown Repair—unplanned outage but to some extent related to the amount of planned maintenance carried out.

The CEGB employs all three kinds of maintenance, the mix being determined by the position of the plant in the merit order.

[1] An outage is the period when plant is not available to generate electricity as a result of planned maintenance or breakdown.

8.5. The maintenance pattern is combined with a degree of risk management at most conventional power stations. If plant shows signs of a developing fault, the probable cost of plant failure is balanced against the saving in immediate outage cost which would be achieved by allowing the plant to be run until a planned outage occurs, and a course of action is then decided.

8.6. The object of maintenance planning is to achieve the lowest overall total of maintenance and outage costs, commensurate with meeting consumer demands, within the restraints of statutory inspection periods, manufacturers' delivery dates for repair or replacement, and availability of labour and materials within the Board and/or from contractors. We now discuss how the CEGB's maintenance policies are affected by statutory and other constraints.

Statutory requirements

8.7. The CEGB is subject to various statutory obligations, including environmental and safety requirements. The latter have a distinct bearing upon availability.

SAFETY

Conventional plant

8.8. The statutory provisions which chiefly affect the operation of conventional plant are:

Sections 33, 35 and 36 of the Factories Act, 1961;

The Examination of Steam Boilers Regulations (SI 781/1964) made under Section 33; and

certificates of exception issued under the Factories Act by the Factories Inspectorate.

8.9. A problem has been that the statutory prescribed periods for which plant is allowed to run between inspections do not always coincide with the most convenient overhaul intervals. Overhauls are scheduled so far as possible during the summer so that all plant is available (apart from breakdowns) to meet the winter peak. These difficulties have been met by the Factories Inspectorate to a certain extent by issuing certificates of exception.

Nuclear plant

8.10. The operation of the Board's nuclear stations is controlled by the Nuclear Installations Act 1965, which requires that a Site Licence should be issued for the building and operation of nuclear reactors. Each of the Board's nuclear stations has, therefore, a Site Licence granted by the Health and Safety Executive. The Site Licence specifies the frequency at which the reactor, the boilers, and the pressure circuit should be inspected and states that following such an inspection the reactor should not be started up before approval has been obtained from the Health and Safety Executive. This approval is issued by the Nuclear Installations Inspectorate (NII).

8.11. The effect of the statutory constraints upon the availability of the eight Magnox stations has been significant. Operation of the Magnox stations started with Berkeley and Bradwell in 1962, followed by Hinkley Point, Trawsfynydd and Dungeness 'A' in 1965, Sizewell in 1966, Oldbury in 1967 and Wylfa in 1971. In the early years the reactors were operated up to the maximum temperatures and power outputs permitted by safety requirements and it was possible to limit outages for statutory inspections to periods of six to eight weeks duration.

8.12. However in 1969 following bolt failures in steel sample baskets at Bradwell it was found that steel oxidisation rates were much greater than anticipated at the design stage. Consequently, in order to contain the oxidisation problem, operating temperatures were reduced on all Magnox reactors. This caused the total output of the Magnox stations to be reduced from approximately 4,500 MW to 3,400 MW. The appearance of steel oxidation also meant that further inspections were necessary to monitor its progress and this had the effect of increasing slightly the duration of outages at some stations.

8.13. Following the discovery of steel oxidation the Board had to demonstrate to the NII that the reactors were suitable for a further two years operations following a statutory outage, allowing for the increased oxide which would form during that period. This involved the Board in a large assessment exercise each year when the oxide thicknesses had to be predicted, the bolt failure probabilities calculated and the integrity of the core structures assessed. However, it cannot be claimed that this work directly affected the length of the outage except possibly where additional inspections were required to verify oxide thicknesses, or material specifications etc.

8.14. In line with the practice, being developed world wide, of carrying out inspections of components important to nuclear safety, the CEGB with the full encouragement of the NII, commenced in 1979 a duct-inspection programme. These inspection activities have increased outage times at most Magnox stations by a factor of 4 or 5. Some manufacturing defects were found by methods of inspection which were not available when the stations were constructed. The CEGB believes that these defects have grown no worse during 15 or more years of operation. Since the inspections at Bradwell and Dungeness 'A' in 1979 and 1980, and more recently at Berkeley, the Board has not been able to satisfy the NII that the defects are tolerable. It is therefore possible that repair or replacement of the defective components may be the only solution. Repair is difficult and may require the development of new equipment. Consequently both reactors at Bradwell and Dungeness 'A' and one at Berkeley have been closed down for many months.

8.15. It is hoped that, when all the ducts have been examined at least once and any necessary repairs carried out, the outage times can again be reduced. However, on most of the Magnox reactors this is unlikely to be achieved within four years, and even then it is unlikely that the statutory inspection requirements will be such as to allow outages as short as six to eight weeks.

8.16. The joint concern of the CEGB and the Nuclear Installations Inspectorate for safety as well as for the desirability of extending original designed lifespans, calls for increased spending on maintenance and overhaul. The NII have told us that following in-service inspections by the CEGB an increasing number of faults have been reported to them as being in need of rectification. The implication of this is a large increase in spending by the CEGB.

The equipment constraints

8.17. We have examined the operating history of plant procured by the CEGB over the past 20 years and the reasons for the variations in plant availability demonstrated through that period. Table 8.1 illustrates the national peak availability of CEGB plant for the years 1959–79, and Table 8.2 indicates both the peak and average availability of conventional plant of 500 MW or above since inception.

TABLE 8.1 **Availability of CEGB plant (conventional and nuclear)**
Annual average at time of peak (working days)

Year	*Declared* Net Capability* MW so	*Loss of availability due to:* *Overhaul* %	*Breakdown* %	*Other causes* %	*Total loss* %	*All plant availability* %	*500/660 MW plant availability* %
1958–59	23,400	9·8	6·7	1·4	17·9	82·1	—
1959–60	25,529	8·3	6·8	2·1	17·2	82·8	—
1960–61	27,067	7·2	8·8	1·9	17·9	82·1	—
1961–62	28,959	8·6	6·9	1·9	17·4	82·6	—
1962–63	31,687	9·3	7·6	2·2	19·1	80·9	—
1963–64	33,157	10·0	11·4	1·5	22·9	77·1	—
1964–65	34,359	11·3	11·3	1·3	23·9	76·1	—
1965–66	36,905	9·2	14·0	2·4	25·6	74·4	—
1966–67	38,468	9·5	14·6	1·3	25·4	74·6	—
1967–68	41,944	11·5	12·7	1·2	25·4	74·7	—
1968–69	44,673	13·0	13·3	1·6	28·0	72·0	35·2
1969–70	46,857	12·0	17·2	2·7	31·9	68·1	39·7
1970–71	49,281	15·1	17·3	3·6	35·9	64·1	45·2
1971–72	54,322	14·7	16·7	2·6	34·1	66·0	50·0
1972–73	56,427	15·4	19·0	1·6	36·0	64·1	50·9
1973–74	58,026	15·5	19·8	1·4	36·7	63·3	54·6
1974–75	58,523	15·0	18·9	1·4	35·3	64·7	55·0
1975–76	58,677	14·8	17·0	0·9	32·6	67·4	57·0
1976–77	56,365	14·4	15·0	1·8	31·2	68·8	61·4
1977–78	56,326	16·8	14·5	1·4	32·7	67·3	61·3
1978–79	56,129	12·1	13·5	1·5	30·6	69·5	69·0
1979–80	57,029	14·6	12·3	1·9	28·9	71·1	69·4

Source: The CEGB

* DNC at the end of the financial year; availabilities are based on the average DNC for the year.

TABLE 8.2 **Plant availability of conventional 500–660 MW units**

Year	*1968–69*	*1969–70*	*1970–71*	*1971–72*	*1972–73*	*1973–74*
Availability %	*(35·2) †56·3	(39·7) 53·9	(45·2) 62·8	(51·0) 62·5	(50·9) 69·4	(54·6) 69·1
Year	*1974–75*	*1975–76*	*1976–77*	*1977–78*	*1978–79*	*1979–80*
Availability %	*(55·0) †75·2	(57·0) 70·8	(61·4) 74·2	(61·3) 75·3	(69·0) 84·6	(69·4) 83·9

Source: The CEGB

* Average annual availability at time of peak (working days).

† Availability at times of daily peak on weekdays in the winter period (December, January and February).

8.18. The availability of 60 MW and 100–120 MW plant was until recently higher than that of larger units. The development from 30 MW to 120 MW units was based on known criteria and characteristics, drawing upon previous operating knowledge for the uprated design. However, the development of 200 MW, 275 MW, 300 MW, 350 MW, 500 MW and 660 MW generating sets each necessitated significant changes in design, and many new designs were developed before the older designs were proved in service. Moreover, competing designs were bought for most of these sizes.

8.19. The earlier 100/120 MW sets also had the benefit of inbuilt conservatism in the design. This plant could be operated up to and beyond its originally expected useful life because more than adequate design margins had been allowed for.

8.20. Designers tended to use higher operating temperatures for the 500 MW plant and to reduce design margins to achieve greater economies of scale. More reliance was placed on sophisticated controls to keep plant within its stated operating characteristics. However, operating closer to design limits can lead to either increased failure or reduced performance.

8.21. Table 8.3 below indicates average availability for 60 MW, 120 MW and single-shaft 500/660 MW plant after five years in service.

TABLE 8.3

Nominal unit size MW	*Weighted mean annual availability in the sixth year of operation*	*Standard deviation*
60 MW	87·7	4·2
120 MW	71·2	12·9
500/660 MW	56·1	10·2

Source: The CEGB

8.22. Table 8.4 shows the national statistics for loss of availability due to breakdowns in 1979–80 for all plant of 500 MW and above, analysed into plant functions. In past years typical reasons for failure in Group 1 include boiler tube leaks and weld failures, erosion of tubes, localised overheating and poor water flow. Milling plant breakdowns figured high in outage losses in the past but the reasons for failure are understood and later designs have been more reliable. In Group 2 of the table typical past failures have been cracked rotors, stator earth faults and stator coolant leaks. Again these problems are now understood and later designs have improved reliability.

8.23. These comments must, however, be viewed in the context of the 1960s when economic growth projections indicated that the medium ranges of plant then available would not satisfy the forecast demand for electricity within the required timescale and new designs had to be produced urgently. With hindsight it is clear that inadequate design proving took place. However, the rate of growth was lower than had been projected and the actual demand

TABLE 8.4 **Loss of availability due to breakdown—1979–80 Conventional 500 MW and 660 MW stations**

Components	*Total loss MWH*	*% loss*
Economiser	1,747,443	0·82
Furnace	2,941,500	1·37
Superheater	2,530,588	1·18
Reheater	3,037,843	1·42
Other pressure parts	710,091	0·33
Attemperator systems	418,493	0·20
Forced draught fans	68,573	0·03
Air heaters	474,488	0·22
Oil firing system	33,876	0·02
Coal firing system	4,144,255	1·93
Sootblowers	116,375	0·05
Auxiliary & structures & control system	290,508	0·14
Gas system	202,428	0·09
Precipitators	1,053,486	0·49
Induced draught fans	401,673	0·19
Sub-totals for Group 1	18,171,620	8·48
High pressure & intermediate pressure turbines	3,051,410	1·42
Low pressure turbines	2,159,817	1·01
Turbo-generator oil systems	304,346	0·14
Rotor assembly	1,142,383	0·53
Exciter system	215,275	0·10
Stator & connexions	2,730,678	1·27
Gas turbines, structures, switchgear, protection system	57,090	0·03
Governor & hydraulic system	218,676	0·10
Condenser	705,200	0·33
Turbo-generator auxiliary system & control	1,811,420	0·85
Condensate & feed heating system	1,423,937	0·66
Turbine feed pump	557,607	0·26
Electric feed pump	292,158	0·14
Start-up & emergency feed pump system	427,209	0·20
Sub-totals for Group 2	15,097,206	7·04
Remainder	822,633	0·38
Grand totals	34,091,459	15·90

Source: The CEGB

for energy at that time was met. The CEGB's efforts over the past ten years have now largely overcome the problems of these designs. Winter availability has risen from 56·3 per cent in 1968–69 to 83·9 per cent in 1979–80.

8.24. The experience outlined above has prompted the CEGB to spend substantial sums of money to rectify design shortfalls and improve quality assurance within manufacturers' works.

8.25. The Board includes two specifications in its invitations to tender:

(*a*) a performance specification, against which a manufacturer submits his proprietary designs; and

(*b*) a quality specification, relating mainly to materials and workmanship.

The CEGB has stated that in the past there has been a presumption that the submitted proprietary design would meet the performance specification. Experience with the 500 MW sets in the 1960s proved this not to be so; and as no station ordered since Drax in 1966 has yet come into full commission, no conclusion can be drawn about improvements since the Wilson Committee report (Cmnd 3960).

8.26. We have been concerned during our investigations about the consequences of the CEGB having power stations with equipment supplied by a large number of manufacturers, each with its own proprietary designs. This multiplies the problem of holding sufficient spares, and reduces the possibility of standard maintenance procedures, both because of inherently different operating characteristics of equipment fulfilling the same function and because of major differences in the frequency with which repairs have to be carried out. The number of suppliers of spares cannot be reduced because of the existence of proprietary design rights.

8.27. The CEGB has adopted policies which are intended to make it easier to maintain, and to keep in service, power stations now under construction or about to be ordered. Every station but one ordered since 1966 has turbine-generator sets of 660 MW; and the odd one has sets of the same design as certain existing stations; already advantage has been taken of the interchangeability of important parts between stations under construction and stations in service. The Board also sees advantage in the acquisition of design rights so that different manufacturers can be invited to tender to supply plant to a standard design. Replication of design is also seen as desirable, but almost impossible to attain when there are long intervals between successive orders.

The management of maintenance in CEGB power stations

8.28. We have examined maintenance and its control in a variety of power stations. We have found that the degree of sophistication practised varies with the needs of the particular station. As stated previously, the position in the merit order, the plant's load factor and the plant's age play a significant role in determining the resources to be applied to the maintenance planning function. All plants have common planning objectives, although the desired time response and complexity of the information required varies. The higher merit order stations generally are making increasing use of computer software to assist in the maintenance process, producing PERT networks and other aids as necessary to achieving the required plant overhaul effort in the time allowed. The methods used for the older and lower merit order plant depend less on computer assistance, with most planning being carried out manually.

8.29. All stations use job process sheets and measured standards for maintenance work. Returns are made by each station monthly on the achieved performance against the measured standards. The proportion of non-measured work is also logged and corrective action taken to retrieve unacceptable deviations. The CEGB is regarded as a leader in this field and is able to market these work measurement systems to foreign utilities.

8.30. The amount of money spent on maintenance at each station is strictly controlled at Regional level. Moreover, savings against budget for low merit stations can often be reallocated by the Region. We have been particularly impressed with the professionalism of Station Managers and their staff. The high level of motivation at all power stations visited has been commendable.

8.31. All levels of management of the stations visited were aware of the importance of cost containment, due in part to the merit order system. In the smaller stations the adaptability of the labour force contributed to the reduction of costs; some of these stations are retained as a reserve, and generate as little as one per cent of their potential annual output.

8.32. All stations visited conducted continuing post design work on plant in efforts either to overcome plant deficiencies or to improve initial designs in order to increase thermal or cost efficiency.

8.33. We have examined the performance of the CEGB both in reducing the length of a planned outage and in meeting planned timescales. Table 8.5 below illustrates the CEGB's total planned outage programme, the slippage or overrun, and the total overhaul commitment for 500/660 MW plant since 1968–69, all measured in terms of percentage loss of availability. It can be observed that generally the total overhaul commitment has been decreasing, and the slippage against the plan has been reduced considerably. The planned outages appear now to have been stabilised, reflecting the sums spent in the past five years to improve availability and the CEGB's experience with this type of equipment.

TABLE 8.5 **Planned outage and overrun performance**

	*Loss of availability %**		
Year	*Basic plan*	*Overrun*	*Total overhaul*
1968–69†	8·4	12·4	20·8
1969–70†	6·4	1·7	8·1
1970–71†	5·5	3·2	8·7
1971–72†	8·2	5·3	13·5
1972–73†	11·1	3·6	14·7
1973–74†	14·6	3·0	17·6
1974–75†	12·6	4·0	16·6
1975–76†	12·8	3·6	16·4
1976–77	12·2	4·2	16·4
1977–78	10·8	4·3	15·1
1978–79	10·3	1·7	12·0
1979–80	12·1	2·8	14·8
1980–81	10·6	0·8	11·4 (est)

Source: The CEGB

* Annual average loss at time of peak (all days).
† The information for these years relates to only four of the five Regions, as one Region was not able to supply details prior to 1976–77.

We are told by the CEGB that the above overruns are partly due to

(*a*) additional work found necessary during a planned overhaul; and

(*b*) conscious decisions to extend an overhaul past its planned conclusion date in order to spread resources or bring forward further work when it is apparent that the original planned outage has to be extended.

8.34. The success of the Board's power station maintenance efforts can be demonstrated by Table 8.6 which indicates the significant reductions in unplanned outage for conventional plant of 500 MW and above for the years 1968–69 to 1979–80. The combination of the Board's continuing post-design efforts and close monitoring of station performance has resulted in the Board almost achieving the level of 85 per cent winter availability assumed for the purpose of setting the planning margin. This level of performance has, however, taken over ten years to achieve, at a cost of the order of 5 per cent to 10 per cent of the capital cost of the stations.

TABLE 8.6 **Unplanned loss for 500 MW and above plant for the years 1968–69 to 1979–80**

Year	*Declared Net Capability** *MW so*	*Breakdown loss†* %
1968–69	7,259	41·7
1969–70	9,472	51·1
1970–71	12,860	42·5
1971–72	17,022	33·9
1972–73	19,563	31·9
1973–74	21,213	26·9
1974–75	22,472	24·7
1975–76	23,578	24·4
1976–77	24,133	21·5
1977–78	24,168	24·0
1978–79	24,528	17·4
1979–80	24,828	14·5

Source: The CEGB

* DNC at end of financial year for this tranche of plant.
† Estimate based on actual MWH loss less 1·5 percentage points to give equivalent peak figures.

8.35. The continuing efforts by the CEGB to alleviate the original disappointing performance of plant can be demonstrated by the index of repair and maintenance costs for the 500/660 MW plant shown below at Table 8.7. These costs do not, however, include the consequential cost of lower merit order plant having to be used to generate electricity when the large sets are not available.

TABLE 8·7 **Index of repair and maintenance (R & M) costs in real terms for single-shaft 500/660 MW plant (index of 100 for the year 1974–75)**

Year	*1974–75*	*1975–76*	*1976–77*	*1977–78*	*1978–79*	*1979–80*
R & M cost index	100	118	117	120	126	137
Winter availability %	75·2	70·8	74·2	75·3	84·6	83·9

Source: The CEGB

Quality Assurance

8.36. Quality Aussurance is the term used to denote an integrated approach to all aspects of quality, which ensures that the operational performance of a product is appropriate to the users' requirements. It includes evaluation of user requirements, verification of design and the setting of quality standards. It also requires the development of management procedures to ensure manufacture to required standards and the proper installation and use of equipment.

An important facet is the amount of quality assurance work carried out after commissioning, when plant is in normal use. It is essential that the information obtained from inspections and usage reports should be fed back and used to amend and improve future design and quality.

8.37. The Board has quality procedures covering most aspects of procurement from initial design through to plant commissioning. These Quality Assurance standards (Ref QA 42–1, 2 and 3) follow closely BS 5750: 1979 parts 1, 2 and 3 and also BS 5882: 1980. The Contractor Assessment Quality Assurance procedures follow closely those of Government procurement agencies, especially DEF — STAN 05–21 to DEF — STAN 05–29/1 as applicable. We are satisfied that in the procurement of plant the procedures laid down are adequate. However, this degree of sophistication of quality assurance is not carried through to the Board's own maintenance operations within power stations after plant has been commissioned.

8.38. In fossil-fuelled power stations in particular, the emphasis is upon control of quality by inspection rather than upon full quality assurance. The Director of Engineering, the Scientific Services Department and specially appointed Boards of Inquiry all play important roles in fault analysis, but these analyses are normally undertaken only when a major fault or abnormal situation occurs. At only one station among those we visited was there a formal analytical procedure for determining all plant deficiencies and identifying their sources. The analysis assigns the cause of each fault to one of four categories: design, quality, operational or maintenance deficiencies. As a result management is able to evaluate fully the performance of the station and its equipment.

8.39. Again, in fossil-fuelled power stations, there is no fully integrated reporting system for the collection of all significant data. Nevertheless, in the past year the CEGB has made significant improvements in the acquisition of data on faults, outage losses and reliability as a result of developing the PRA (Plant Reliability/Availability) system. This system could, with advantage, be developed to provide a data base for all significant faults rather than only those causing loss of availability as at present.

8.40. Moreover, in most power stations control of quality is diffused amongst the respective line engineers responsible for sectors of the maintenance programme. In times of pressure 'to get back on line' it is possible for quality standards to be depressed in favour of job completion. Given the high consequential outage costs of large stations, and the experience at one station in the South Western Region of a unified approach to quality assurance, there may be a case for all stations of 500 MW and above to make quality assurance the responsibility of a single nominated individual (free from control by other functions) in order to improve quality awareness significantly. The functions of such an individual could be:

(*a*) to implement improved quality procedures on site and conduct periodic quality assurance audits;

(*b*) to conduct in-depth cause and effect analyses of all failures on site, whether loss of availability was incurred or not;

(*c*) to provide a formal link for all data transfer between stations, Regions and HQ in relation to plant operating criteria; and

(*d*) to liaise with PIT (the CEGB quality agency) and other CEGB suppliers' quality organisations to ensure that quality defects in supplied equipment, and design deficiencies, are reported through to the Region, Barnwood, and the equipment supplier.

8.41. The CEGB has recognised the need for improved communication with its suppliers of major plant, as the recently constituted Plant Manufacturers Co-ordinating Committees demonstrate. We believe that a greater degree of formal reporting of plant operating experience would be a valuable input to such liaison initiatives.

International comparisons

8.42. We have made enquiries of foreign utilities in respect of electricity generation and availability of plant. The replies received have confirmed that comparisons of international practice must be treated with caution unless the qualifications necessary for interpreting the raw data are fully understood. We believe that a fair and balanced comparison would be very useful; but it would require an exercise in greater depth than we have been able to undertake.

Conclusions

8.43. We have examined the maintenance of power stations and are satisfied that, in this respect, the power stations are well managed. We note that availability of large conventional stations has improved considerably in recent years. However, we draw attention to the continuing difficulties concerning the availability of nuclear plant.

8.44. The systems of reporting equipment shortcomings to Regions, to Barnwood and to suppliers of equipment are fragmented and could be improved by the provision of a single formal integrated information system.

8.45. The CEGB's experience in operating plant should be taken more fully into account in new plant designs. A means of achieving this would be for the CEGB to introduce improved data reporting systems in order to increase manufacturers' understanding of the reliability and integrity of their products in service.

8.46. We recommend that full Quality Assurance procedures should be introduced at power stations with sets of 500 MW and above. In addition to improving management's knowledge of the causes of outage, they would indicate the areas where remedial action might avoid breakdown. There should be a nominated person with clearly defined responsibility for quality in such power stations. He should not be subject to control by other functions.

CHAPTER 9

Plant spares

9.1. There are two major classes of plant spares: 'Regional spares', which encompass a large number of items of many different kinds; and 'National spares', which comprise a relatively small number of substantial items (eg stators, rotors and transformers) usable in more than one Region and which it would not be economic for any individual Region to hold. Regional plant spares, stocks of which in 1980 were nearly six times the value of National spares, are held at individual power stations: National spares are held either at Didcot or at Manchester.

Regional Plant Spares

General

9.2. The total value of plant spares (both revenue spares and capital spares[1]) held by Regions at the end of March 1980 was of the order of £190 million. Although this is only about 4 per cent of the value of the CEGB's net assets at historic cost, it represents a considerable sum in absolute value. In order to assess the effectiveness of the Board's policies and practices in the ordering and holding of Regional plant spares, we undertook a special study with the help of consultants.

9.3. The Board has, in recent years, commissioned a number of new power stations of high thermal efficiency which stand high in the merit order. If a generating set at one of these stations breaks down it can cost the CEGB up to £160,000 a day (see paragraph 8.3) to use less efficient plant in substitution. The Board has therefore invested significant sums both to ensure adequate stocks of spare parts for existing plants and to provide sets of spares for new plants. Table 9.1 illustrates the growth in value of revenue spare stocks in each Regions:

TABLE 9.1 **Regional stocks of revenue spares (£ million in historic prices)**

At 31 March	*North Eastern* £m	*North Western* £m	*Midlands* £m	*South Western* £m	*South Eastern* £m	*Total* £m
1974	9	NA	NA	NA	9	NA
1975	13	NA	NA	9	9	NA
1976	19	NA	NA	13	13	NA
1977	23	NA	NA	11	17	NA
1978	27	15	34	19	21	116
1979	33	18	37	25	22	135
1980	38	21	44	32	30	165

Source: The CEGB

Note. These figures exclude capital spares whose total value at 31 March 1980 was about £20–£25 million.

[1] Capital spares are items valued at £1,000 or more which are returned to use after refurbishment. They represent a little more than 10 per cent in value of total Regional plant spares.

9.4. If the figures in paragraph 9.3 are adjusted for inflation using an index derived from wholesale price indices for mechanical engineering and electrical engineering materials, the result shown in Table 9.2 suggests that the volume of stocks in recent years has risen substantially:

TABLE 9.2 **Stock levels valued at constant (1980) prices £ million**

At 31 March	*North Eastern* £m	*North Western* £m	*Midlands* £m	*South Western* £m	*South Eastern* £m	*Total* £m
1974	20	NA	NA	NA	19	NA
1975	25	NA	NA	18	18	NA
1976	32	NA	NA	22	22	NA
1977	33	NA	NA	16	25	NA
1978	35	19	45	25	27	151
1979	38	21	43	29	27	158
1980	38	21	44	32	30	165

Source: Monopolies Commission Study.

Note: The figures are somewhat understated because they include items purchased in earlier years and not revalued. The price index used may also tend to understate price increases during the period because it excludes certain labour costs.

We were told by the CEGB that the increases over the last ten years, reflected in the above two tables, have taken place almost entirely at the 500/660 MW stations, and have occurred for a number of reasons. These reasons include the limited interchangeability of spares, the desire to increase station availability and so to save outage costs, plant experience, destocking by manufacturers, the effect of minimum order lots and minimum production runs and the fact that manufacture of some items was about to cease.

9.5. The general policy of the CEGB is to hold Regional plant spares at generating stations. This has the advantage of giving readier availability of spares 24 hours a day. Even when two stations have identical equipment, spares are held at one of them rather than at a third location. Stockholding costs are thereby reduced, and the costs of delay and distribution are incurred on average on only half the occasions when a spare is required. Movements of spares between stations and Regions are fairly free and formal procedures do not prevent speedy action in an emergency.

9.6. When a station is under construction, the CEGB receives a list of recommended spares from the manufacturer. This is reviewed by a specially constituted committee for that station and recommendations are made as to a suitable spares inventory. In doubtful cases, a special risk analysis may be carried out to determine the matter. Apart from this we have detected no corporate policy as to the level of plant spares a station should hold, or the level of ex-stock availability which should be achieved, although the Board has told us that provision is now being made, where appropriate, to introduce stock control algorithms into computer-based systems.

9.7. It is the Board's policy, when it has surplus stock or when a station is to be closed down, to circulate lists of spares initially to other stations. Any parts not needed are then disposed of, the Board generally seeking competitive tenders for them.

9.8. It has not been the Board's policy, under historic accounting conventions, to revalue spares because of inflation or to depreciate them individually as the probability of obsolescence increases, but this will change with the adoption of current cost accounting. Meanwhile, an obsolescence allowance (one-thirtieth a year of the total value of stock held by a station, or one twenty-fifth in the case of nuclear stations) has recently been introduced; this is treated as part of power station works costs. Additionally, provision of about £20 million has been made to cover older stations where the annual provision could prove insufficient. It is also not the Board's policy to charge a station interest on the value of its stockholding, although it uses a figure of 25 per cent when calculating the most economic ordering level.

9.9. The Board has now instructed Budget Centres to do all they can to ensure that the value of stocks and spares does not increase in real terms, but no guidance has been given on the way in which this fixed sum should be allocated among all items to give the best result in terms of overall availability.

Regional Stockturns and Service Levels

9.10. The levels of stock in terms of months supply vary between Regions and in part this difference is explained by different stock accounting procedures—particularly in relation to the South Western Region. But, where figures across all Regions are available for a number of years, they indicate a substantial increase in real levels between the early part of the decade and 1979–80, though all stock levels are currently below their highest. Table 9.3 shows the Regional position for revenue spares at the end of the financial year when stocks are usually high in readiness for the summer overhaul programme.

TABLE 9.3 **Regional stock levels in months' usage**

31 March	*North Eastern*	*North Western*	*Midlands*	*South Western*	*South Eastern*
1974	15·5	NA	NA	NA	33·0
1975	22·5	NA	NA	54·0	31·5
1976	28·5	NA	NA	78·0	41·5
1977	30·5	NA	NA	33·0	48·5
1978	36·0	NA	39·0	57·0	42·0
1979	33·0	42·5	37·0	50·0	40·0
1980	30·5	34·0	36·5	64·0	42·0

Source: The CEGB.

9.11. The management control information of Regions does not show what proportion of demand for spares is satisfied from stock. However, two stations in the North Eastern Region (Thorpe Marsh and Ferrybridge C) do maintain such information: additionally, sample checks were carried out for our inquiry. The results (all relating to periods from February to August 1980) are shown in Table 9.4.

TABLE 9.4 **Sample of proportion of spares satisfied from stock** (February/August 1980)

Station	*requested* (1)	*Number of items issued* (2)	*% satisfied from stock* (3)
Thorpe Marsh	886	852	96·2
Ferrybridge C	1,846	1,804	97·7
Ratcliffe	533	418	78·4
High Marnham	705	600	85·1
Kingsnorth	175	165	94·3
Tilbury B	65	60	92·3
Drax	251	235	93·6
Fawley	1,139	1,133	99·5
Oldbury	520	510	98·1
Fiddler's Ferry	2,200	2,180	99·1

Source: The CEGB

Note: It will be noted that eight of the ten stations achieved service levels of over 92 per cent. Methods of recording the underlying data may differ between stations and too fine an interpretation should not be placed upon the figures.

Stock Records and Control

9.12. The CEGB has a well-developed national commodity code covering all Regional plant spares, which comprise 40–50 per cent of the value of all Regional stores issues. Most Regions now have computerised stock ledgers at their Headquarters recording all transactions for other than low value, high usage consumables for which there is a simplified issues system. Items which fall within the simplified issues system comprise roughly 20–25 per cent of the total value of Regional stockholdings but 80–85 per cent of the total number of items issued. Issues and receipts for other than simplified issue items can be analysed by station and by individual type of spare.

9.13. In the South Western Region, there are on-line Stores Operating Systems at the seven major station sites, including the three nuclear sites. These systems enable all transactions (other than simplified issues) to be recorded as they occur, and allow remote interrogation of stock availability by engineers. However, we note that it is not currently permitted for one station to interrogate the stock file of another, although, given the code and the necessary facilities, it is technically possible. We were told that the reason for this is the Region's desire, during the development of the on-line system, 'to maintain the integrity of each location's stocks which are the responsibility of each Station Manager'. Such enquiries must therefore be routed through Regional Headquarters or made informally by one engineer telephoning another.

9.14. Consumption of each item of plant spares (other than simplified issues) and other major valuable items at each station is recorded individually on a materials record card. In due course the use of such cards will cease in those stations where on-line computer systems have been introduced. In the case of medium to high usage items (which include simplified issues) guidance on re-order levels and re-order quantities is provided to stores and engineering personnel by means of a ready reckoner which indicates the appropriate levels and quantities for various usage rates and delivery periods. Personnel on many stations, however, prefer to use their own engineering and store-keeping judgment. In the case of the slower moving, higher value plant spares, there is no algorithm to aid the engineer or storekeeper to set stock levels and thus judgment has to be exercised on the 10,000 to 30,000 items concerned. Where very high value plant spares are concerned a formal case, backed by detailed cost and DCF analysis, is prepared for eventual authorisation by the Director of Production.

Purchasing Procedures

9.15. The CEGB's policy of delegation of authority to its managers places upon Directors General of the Regions and Divisions the responsibility to procure the Regional plant spares and services necessary to discharge their tasks within approved budgets. Where proposed expenditure exceeds the delegated authority the approval of the Executive must be sought.

9.16. The Board has also established a Purchasing Policy Group charged with the responsibility for examining the existing organisation and practices in purchasing and to make recommendations to the Board on changes.

9.17. Where purchases of any one type of product or service are significant or of a specialist nature, they may be procured under national contracts by specialist purchasing teams. One such team, located within the Headquarters Operations Department, is responsible for the negotiation of contracts and agreements for the supply on a national basis of consumable engineering materials of such significant or specialist nature.

9.18. Within the Regions purchasing is the responsibility of the Regional Purchasing, Contracts and Stores Officer or his staff, upon whom requisitions for the relevant plant spares and materials are placed by users or stockholders (ie power stations). Following receipt of a requisition, the Purchasing Officer (except in the case of centrally purchased goods—see paragraph 9.17) compiles a list of suitable suppliers. Tenders are then sought and, when received, are opened formally by a Tender Panel. There are two exceptions to this:

(*a*) small value items up to £1,500 for which either single quotations are sought, evaluated and contracts placed by individual staff at Regions; or, in the case of very small value items (up to £350), supplies are obtained by Local Purchase Order; and

(*b*) certain items for which there is but a single supplier.

9.19. Once a contract for original equipment is let, albeit competitively, the subsequent supply of spares must largely come from the main contractor or his sub-contractor unless standardised designs of components are used. Additionally, a number of items are available—even as original equipment—from one supplier only. Thus competitive tendering is possible for only a part of the Board's plant spares purchasing activities. It is estimated that the CEGB has to resort to single tender action in 65 per cent to 75 per cent (by value) of its plant spares purchases. This proportion is unlikely to decrease—indeed it may well increase since the Board's new policy of replication will tend to favour the company which built the previous equipment.

9.20. This situation, and the inflationary conditions of recent years, has led the Board to adopt a number of procedures to contain costs in single tender cases:

(*a*) If a spare part has been purchased previously, the new and the old price are compared against the most relevant official materials price index: an excessive increase in the new price is challenged.

(*b*) If there is no previous purchase history and it is suspected that the price is too high, a check will be made with the relevant CEGB station engineer and, if he confirms the suspicion, the price will be challenged.

(*c*) For substantial items some companies will agree to work on a cost disclosure basis (ie raw materials, labour hours and rates, overheads and profit recovery). Discussions are under way with the two turbine manufacturers with a view to extending the assessment of non-competitive work and it is intended shortly to undertake similar discussions with the major boiler manufacturers: these discussions cover half of the single tender purchases.

9.21. Occasionally, a component which proves unsatisfactory in service is re-designed by the Board and a competitive quotation may thenceforward be obtained. Additionally, the Board has rights to a supplier's drawings, tools and jigs on its liquidation or when it ceases to manufacture. However, there have not been many such cases.

9.22. Where competitive tenders can be sought, Regions have built up lists of suppliers from past experience. New potential suppliers are added to the appropriate list after commercial and technical checks. Our enquiries showed that there was an active movement onto and off these lists and we concluded that Regions do not operate a cosy relationship with past suppliers.

9.23. As a matter of general convention all Purchasing Officers buy most of their spares from United Kingdom suppliers.

National Plant Spares

9.24. National spares are items which are applicable to more than one Region. An item may be purchased as a National spare if its purchase cannot be justified by any one Region in isolation but is justified for the Board as a whole, or if its purchase centrally will justify a worthwhile reduction in the CEGB's total holdings of such items. The spare may be used either in the event of a breakdown or for planned repair by replacement when on-load tests indicate that a part is developing a fault, or for maintenance or modification. National spares include both generating and transmission components; most of the generating components relate to the large 500 and 660 MW sets.

9.25. The use of National spares reduces costs by saving outage time and thereby increasing the availability of the more efficient large sets. In the short run there is a saving in the alternative generation costs that would otherwise be incurred and, in the longer run, an influence on the level of investment required in new generating capacity. It is difficult to estimate the size of these savings because the CEGB's best policy in the absence of National spares is not known. The CEGB has calculated that 500 and 660 MW unit availability in 1979–80 could have been increased by as much as 10 per cent as a result of its holding National spares, assuming that its policy in the absence of the spares would have been to repair the defective component and re-use it. The level of availability influences the operating plant margin and the planning margin (see paragraph 4.57). It is therefore very important for the CEGB to satisfy itself that the National spares holding is at the right level, given the other opportunities it may have for the limited investment funds available.

9.26. A National Spares Plan is prepared each year by the Operations Services Branch of the Operations Department in conjunction with the Regions and Divisions; this Plan is designed to give the Executive a view of the position for the next three years. The total book value of National spares held at 31 March 1980 was £33·1 million. The 1980 National Spares Plan proposes expenditure of about £25 million (in March 1979 prices) for sanction between 1980 and 1983. For each item a detailed scheme and economic appraisal is prepared and circulated to Regions for comment and support. Evaluation of transmission spares is carried out on the basis of engineering criteria. Generation spares are treated as optional investment and evaluated on the basis of a three year pay-back period and 15 per cent real discount rate: these financial criteria are used by the Board for all optional investment (see paragraphs 5.17 and 5.18) and were introduced in February 1980 against a background of tightening cash limits.

9.27. For the financial evaluation the cost of acquiring a National spare must be compared with the benefit received from holding it. For this purpose the benefit is regarded as the cost of using less efficient generating capacity during an outage multiplied by the probability of failure of the component.

9.28. The cost of the component is based on a tender received from the manufacturers. The cost of an outage is derived by running the merit order model for the relevant years and is known to the limits of accuracy of that model (see Chapter 6). The more difficult factors to determine are the probability of failure and the outage time saved by the use of a spare. Although most National spares are components for 500 or 660 MW units, these units have not been in service long enough for the CEGB to base its estimates on the data on failures only of units of this size. It therefore uses data on units of 100 MW and over to determine these factors, and considers the outcome as a conservative estimate of the probability of failure and the length of time needed for repair.

9.29. A more difficult problem now facing the CEGB is that components of large generating units will begin to fail owing to problems associated with their age, and national spares will be needed as replacements. For the moment judgments on failures not so far experienced in the United Kingdom will have to be based on a combination of engineering judgment and experience in other large countries of using large modern plant.

9.30. The treatment of National spares as optional investment (see paragraph 9.26) raises the question of the best use of resources. The Board has told us that the optional criteria have not limited investment in National spares. However it does have a list of National spares projects which would earn a 15 per cent rate of return (and pay back their capital in between 3 and 7 years) but are not to be undertaken. Without a complete list of all the investment projects and their rates of return considered by the Board we cannot judge whether these projects should have gone ahead.

Conclusions

Regional Plant Spares

9.31. It is our view that in matters of purchasing and stock control the Board has in the past relied upon the judgment of competent and resourceful engineers capable of managing risk, making temporary repairs, exchanging spares between stations and using alternatives. This policy has helped to maintain a high level of availability in the generating system. Nevertheless this approach has, in our view, obscured the need and reduced the motivation, for detailed Operational Research studies and the introduction of more advanced methods of stock control—although, as indicated in paragraph 9.6, this may be changing.

9.32. The need for models to aid the judgment of engineers and storekeepers is reinforced by the Board's recent instruction to Budget Centres to do all they can to hold stocks of spares constant in real terms, since the Board has no method for translating this instruction into an optimal mix of stock, balancing the claims of competing needs. Moreover, in this respect the Board will come under increasing pressure as the new larger stations come into operation and their necessary spares holdings are only partially compensated by the closure of smaller stations. We recommend that the Board should develop such new methods of stock management; it will be a formidable task but the rewards could be considerable. Its spares holding is expected to be around £200 million by the end of 1980. Commercial experience suggests that savings of 20 per cent of stock without detriment to service levels are possible using mathematical models. On the other hand, since there can be very high consequential costs to the CEGB of running out of some spares, it may be possible to achieve overall savings by increasing service levels in particular cases, rather than by reducing stocks. In practice both may be possible.

9.33. As an interim measure to encourage efficiency in the use of present stocks, we recommend that the Board should charge Regions interest on the value of stocks held.

9.34. Additionally, whilst considerable flexibility in exchanging spares between stations and between Regions was noted, such exchanges would be facilitated if inter-station interrogation on line of all stock files were to be allowed.

9.35. On single tender contracts, we recommend that Regions should institute the systematic recording of the number and percentages of prices asked, challenged and paid. Chief Purchasing Officers from the various Regions could then meet periodically to compare notes and discuss their successes and failures so that they could bring together and strengthen their cumulative experience.

National Spares

9.36. The evaluation of proposals to purchase National spares seems to us to be calculated as accurately as possible given the CEGB's limited experience, because of the relatively short time they have been in service, of the types of plant concerned.

9.37. We recommend that the CEGB should consider whether its requirement of a 15 per cent rate of return and a 3-year pay-back for optional investment is causing insufficient investment in National spares.

Regional and National Spares

9.38. We conclude that, in the absence of fully competitive tendering for many substantial items of expenditure, the systematic monitoring and negotiation of manufacturing costs (to be disclosed under agreements with suppliers) is likely to be the most productive course of action.

9.39. We recommend increased use of standard designs owned by the CEGB to permit competitive tendering for, and reduced holdings of, spares.

Chapter 10

Industrial relations and efficient use of manpower

Introduction

10.1. At 31 March 1980 manpower employed by the CEGB (including trainees) totalled 61,726 comprising 817 managerial and higher executive staff, 8,094 administrative and clerical staff, 15,759 technical and scientific staff and 37,056 industrial staff. Labour costs currently represent only 9·9 per cent of the CEGB's total costs, but the cost of labour is more amenable to direct influence than are some other elements of the Board's costs.

10.2. This chapter examines the organisation and performance of the CEGB's personnel function and discusses the industry's industrial relations system, the record of strikes and the handling of power station closures. It then focuses upon a detailed examination of pay levels and output per head in the CEGB. The effectiveness of the Board's policies in containing labour costs and making the most efficient use of manpower are also considered in this chapter.

The Personnel Function

Organisation

10.3. The personnel function is headed by a full-time Director of Personnel Management (DPM). Responsibility for the development of the Board's personnel and industrial relations policy rests with the DPM, in consultation with the Directors General and Personnel Managers and subject, on major policy developments, to approval by the Executive.

10.4. Reporting to the DPM at HQ are three branch heads, responsible respectively for industrial relations and productivity, personnel services, and education and training. The three branch heads have close functional links with the personnel departments in each of the Board's five Regions and three Divisions. The branch head who is responsible for industrial relations and productivity also maintains close working relationships with the Regional Directors of Resource Planning.

10.5. At Regional level the personnel function is headed by a specialist Chief Officer, who reports direct to the Regional Director General but with a strong functional link with HQ. There is scope for variation in the organisation of the function at Regional level. The structure currently in operation in the NE Region is nevertheless broadly typical of the other Regions. It is organised in five separate branches—personnel services and administration; education and training; safety; occupational health; and industrial relations.

10.6. The DPM and senior IR Branch personnel participate in the national negotiating and consultative bodies for the industry, their sub-committees and working parties, etc. The Regional personnel staff participate in the district level machinery and are involved in HQ working parties for examination of particular problems, eg the working party on the role and training needs of foremen was chaired by a Regional Personnel Manager. At local level each power station has its own administrative officer whose duties include part of the personnel function, but the key role in power station personnel and industrial relations decisions lies with the Station Manager, who chairs the management side of the local negotiating and consultative bodies.

10.7. The Board told us that during the 1970s considerable effort had been put in towards developing closer working relationships between HQ and the Regions and Divisions. We were told, by both Headquarters and Regional management, that relations are less formal and more co-operative than previously. The DPM meets the Regional and Divisional Personnel Managers on a regular basis about four times a year to discuss policy issues and practical problems, and at other times as required holds meetings with all or some of them. There is generally considered to be a stronger sense of teamwork than hitherto.

Recruitment

10.8. Conditions of employment in the CEGB compare well with other employers, and the Board has few recruitment problems. Such problems as persist are mainly concentrated in certain specialisms (eg control and instrument crafts) and in particular geographical areas (eg Southampton, Thameside, Teesside) due to competition from other process industries and from North Sea oil. Recruitment problems have eased, even in the specialist crafts, as employment opportunities generally have worsened. Problems are expected in the North East, however, particularly on mechanical engineering craftsmen, as the new coalfield at Selby is developed, and discussions have been opened with the NCB to try to minimise any labour supply difficulties.

Training

10.9. Training is highly developed within the CEGB and the Board's training standards and resources are well regarded outside the industry. The Board's annual training budget amounts to some £25 million (1980 prices) including the salaries of some 2,200 full-time trainees. The bulk of this investment is in craft and engineering training. In other areas, for example plant operations, progress can be made, on successful completion of appropriate training modules and when suitable vacancies arise, to the next higher operating grade. Modular training is currently being developed to assist in the training of craftsmen.

Absence rates

10.10. Absence rates are relatively low and almost entirely sickness related. The average sickness absence overall in 1979–80 was 11·10 days, or about 5 per cent compared with the average of 6 per cent for all industries shown by the Government Household Survey 1980. Within the overall total the CEGB's management staff averaged 2·43 days absence, compared with 4·07 days for the Board's technical and scientific staff, 8·36 days for administrative and clerical staff and 14·84 days for industrial staff. The absence rate for the CEGB's industrial staff represented some 6–7 per cent lost time compared with 7–8 per cent for manual workers in all industries as shown by the GHSS.

Power station managers interview all staff after absence according to well established, formalised procedures which can lead ultimately to the dismissal of staff who fail to maintain an acceptable attendance record.

Labour turnover

10.11. The level of labour turnover in the CEGB—only 7·7 per cent for the Board as a whole in 1979–80—is well below the national average for manufacturing of about 25 per cent. Within the Board's different staff categories turnover rates varied from only 2·2 per cent for technical and scientific staff to 8·6 per cent for industrial staff and 15 per cent for administrative and clerical staff. A high proportion of the last group are clerical and typing staff, for whom higher wastage rates are to be expected.

10.12. The Board has experienced more serious problems in particular geographical areas and in respect of certain categories of employee. Wastage has in the past been high amongst craftsmen in the North East, for example, where about half of them were being lost within about two years following completion of their apprenticeships. The Board has experienced a more general problem of high wastage among post-graduate engineers during the first two years following completion of their training. Such wastage is costly and the CEGB has undertaken special studies to discover what measures might help to reduce it. In the case of craftsmen, wastage has reduced as the national economy has gone into recession; in the case of the post-graduate engineers, the studies showed that lack of job interest was an important factor and the Board is now attempting to provide more interesting work for its newly-trained graduate engineers.

The Industrial Relations System

Trade union membership

10.13. Trade union membership agreements were introduced for industrial staff in 1969 and administrative and clerical staff in 1977. The best available information on the numbers of members in the various unions in the CEGB was published in the Seventh Report of the Select Committee on Nationalised Industries, July 1978. Table 10.1, reproduced from that report, shows the numbers of employees having their union subscriptions deducted from salary. This will in all cases be an understatement of the total union membership because some members prefer to pay their subscriptions direct to the local union representative or through their banks. The CEGB believes that the figures nevertheless provide a useful indication of the extent of trade union membership in each union, but it is likely that union membership in the administrative and clerical area has grown since the introduction of the membership agreement in 1977.

Collective bargaining and joint consultation

10.14. The Electricity Council has responsibility under the Electricity Act 1957 (Section 12) for the establishment and maintenance of machinery for settling terms and conditions of employment in the electricity supply industry in England and Wales. Negotiating machinery with the trade unions is highly

TABLE 10.1 **Employees of the CEGB having their union subscriptions deducted from salary as at March 1976**

	Number	*Number as percentage of staff in group*
Managerial and higher executive grades		
Electrical Power Engineers Association (EPEA)	367	46·7
Association of Managerial Electrical Executives (AMEE)*	—	—
National & Local Government Offices Association (NALGO)	93	11·8
TOTAL	460	58·5
Technical and scientific grades		
EPEA	12,341	84·6
Administrative and clerical grades		
NALGO	5,927	75·8
Association of Professional, Executive, Clerical and Computer Staff (APEX)	163	2·1
Managerial, Administrative, Technical and Supervisory Association (MATSA)	63	0·8
Association of Clerical, Technical and Supervisory Staffs (ACTSS)	61	0·8
TOTAL	6,214	79·5
Industrial grades		
General & Municipal Workers' Union (GMWU)	10,066	28·7
Transport & General Workers' Union (TGWU)	8,987	25·6
Amalgamated Union of Engineering Workers (AUEW)	2,561	7·3
Electrical, Electronic, Telecommunications and Plumbing Union (EETPU)	6,477	18·4
Union of Construction, Allied Trades & Technicians (UCATT)	392	1·1
TOTAL	28,483	81·1

Source: The CEGB

* This union is known to have members but none of them had arranged to have their subscriptions deducted from salary at the time the statistics were compiled.

centralised and the management side of the industry's joint negotiating bodies are chaired by the Electricity Council member for Industrial Relations, who is the accepted management spokesman on industry-wide industrial relations issues. The CEGB has four or five representatives on each of these bodies, drawn from its Board members, the Director of Personnel Management, Regional Directors General, Directors and Chief Officers, and HQ IR Branch.

Negotiation of terms and conditions of employment

10.15. Negotiation of the main terms and conditions of employment is centralised for the industry, embracing the CEGB, the Area Boards, the two Scottish Boards, and the Electricity Council. There are five national negotiating bodies on which the industry's staff are represented by the unions listed below.

(1) The National Joint Managerial and Higher Executive Grades Committee (NJMC) covering managerial staff—EPEA, NALGO, AMEE.

(2) The National Joint Board (NJB) which covers engineers and scientists—EPEA.

(3) The National Joint Council (NJC) covering professional (except engineers and scientists), administrative, clerical and sales staff—NALGO, APEX, MATSA, ACTSS.

(4) The National Joint Industrial Council (NJIC) covering industrial staff other than building and civil engineering—GMWU, TGWU, EETPU, AUEW.

(5) The National Joint (Building and Civil Engineering) Committee (NJ(B&CE)C) covering building and civil engineering industrial staff—UCATT, EETPU, GMWU, TGWU.

The NJIC has existed since 1919, the NJB since 1920 and the other bodies since 1949–50. Discussions are currently proceeding for the formation of a national Joint Negotiating Committee (JNC). This would provide a joint negotiating forum for the determination of matters of common interest which would be referred to it by the national negotiating bodies (eg London allowance, subsistence and car allowances).

10.16. The national level negotiating machinery is supplemented by machinery at district and local levels. The district level machinery is joint between the CEGB and the Area Boards, reflecting arrangements at national level, but the machinery at local level in power stations and other management units is specific to the CEGB. There is little scope for initiatives at district level where most of the business concerns the resolution of disagreements jointly referred by the local units (eg shift rotas). Detailed working arrangements, such as shift rotas following operating regime changes, or payments for working abnormal conditions peculiar to the location, are normally jointly determined at power station level (eg by the Works Committee for industrial staff). Many local issues are resolved informally.

10.17. *Joint consultation* includes those broad strategic issues which fall outside the scope of the negotiating machinery in the industry. These matters are discussed between the Electricity Council, the Area Boards, the Scottish Boards, the CEGB and all the unions in the industry at national level on the National Joint Co-ordinating Council (NJCC) (GB), the management side of which is chaired by the Chairman of the Electricity Council, and the separate Joint Co-ordinating Committees for Scotland and for England and Wales. At district level there is a District Joint Advisory Council (DJAC) based on the geographical structure of the Area Boards which brings all the same parties together. At local level in the CEGB, power station management consults elected representatives of all staff on a Local Advisory Committee (LAC).

10.18. The industry's district level negotiating and consultative machinery is based on the territories of the Area Boards and not on the organisation structure of the CEGB. In consequence, the CEGB's Regions are involved in two, or in some cases, three separate sets of district level machinery. In the NE Region, for example, where the CEGB Region embraces two Area Boards, the personnel department is involved at district level in two District Joint Industrial Councils (DJICs) for industrial staff, two District Joint Boards (DJBs) for professional engineering staff, two District Joint Councils (DJCs) for administrative and clerical staff and two DJACs for all staff, plus involvement in sub-committees.

10.19. Some of the business of these bodies necessarily concerns the affairs of the Area Boards and is of limited interest to the CEGB. There are also problems for CEGB Regional staff in achieving consistency between decisions of different district bodies affecting staff in their Region. These problems have been addressed on the consultative side and the district and local consultative machinery is currently undergoing revision. The DJACs are to be replaced by separate JCCs for each Area Board and CEGB Region. At local level the LACs are to be replaced by LJCCs. At both levels it is intended that greater emphasis will be given to discussion of strategic and policy issues facing the CEGB management.

10.20. *The informal industrial relations system.* There is frequent informal communication between the district full-time TU officers and the Regional and Divisional personnel staff. There are also frequent informal contacts between Headquarters Personnel Department and national TU officers. Relationships are cultivated on both sides and many potential problems are resolved informally before they can develop. There are frequent contacts on a similar basis between Station Managers and the local elected staff representatives. The unions also appoint shop stewards but these have no formal role in the system except where requested, in representing individual members in grievance or disciplinary cases. In practice, most local elected representatives of NJIC staff in the formal system are also shop stewards, but generally the number of shop stewards is too great to permit all of them to be elected to sit on the Works Committee. At some stations all the shop stewards sit on an informal shop stewards' committee but the committee has no formal status and its meetings take place outside working time. Friction occasionally arises between Works Committee representatives and shop stewards but there have been no significant problems arising from this in recent years.

Industrial disputes

10.21. The record over the past ten years includes an official work-to-rule and overtime ban by NJIC staff from 7 to 14 December 1970 in support of a pay claim, causing widespread disruptions to electricity supply, and leading the Government to establish a Court of Inquiry under Lord Wilberforce. NJB staff were involved in a one day official strike on HQ offices on 26 October 1972 in support of a claim for revisions to the HQ salary structure. From 1 November 1973 to 2 January 1974 the EPEA imposed a ban on out-of-hours working in support of their claim for improved payments for these duties and prolonged voltage reductions were necessitated.

10.22. In the autumn of 1974 there was a series of one or two day unofficial strikes in support of pay claims by some NJIC staff in the NE but this had no effect on electricity supply. Also, in 1974, NJC staff (NALGO members) officially withdrew clerical and administrative staff in power stations and computing centres and in certain sections of the SE Region and Board HQ but there was no consequent disruption of supply. Unofficial action in the form of a work-to-rule and overtime ban was taken by a large number of NJIC staff between 6–7 September and 13 November 1977, in support of claims for concessionary staff rates for electricity, travel allowances and improved shift pay, causing the CEGB to impose voltage reductions and disconnections.

10.23. In general there have been relatively few problems giving rise to disruption of production compared with the experience of many other industries in the United Kingdom, and only isolated instances of less serious forms of industrial action. The CEGB has told us that over the 10 year period disconnections have only taken place during 0·15 per cent of total hours and have only affected a small proportion of consumers at any one time.

Contract labour

10.24. The requirements of plant maintenance and overhaul in electricity generation make it essential to use some contract labour, particularly for the major planned outages in the summer months. The NJIC has established joint guidelines on a procedure for discussions on the use of contractors for this work. The issue has not been a significant cause of industrial disputes in the industry although it remains a highly sensitive industrial relations issue.

10.25. It is the CEGB's published policy to complete as much work by the use of direct labour as is practicable and economic and to make best use of its resources, including manpower, by minimising overtime working and by ensuring full use of the provisions of national agreements in particular those which relate to mobility, flexibility, the use of work patterns, redeployment and retraining. The CEGB has undertaken to discuss at least annually at plant level its plans for employing contractors over the coming year and, as far as possible, to reach mutual understandings with staff representatives and district trade union officers. Contractors are used only where this is essential:

(*a*) because specialist plant and techniques are involved;

(*b*) to carry out emergency work;

(*c*) because of the need to relieve work peaks.

10.26. In the event of difficulties arising over the use of contract labour there is an agreed expedited procedure for referring disagreements outside the formal machinery to a full-time district TU official and, if necessary, via Regional management to the Director General. It is apparently not unknown for local shop stewards to seek to negotiate increased overtime as a partial alternative to accepting the use of contractors. Local management may sometimes consider it appropriate to reach understandings with them about the correct division of work and hence the levels of overtime that will be made available to permanent maintenance staff to complete the task.

Plant closures

10.27. The pace of technological change in the electricity generating industry has been rapid during the post-war period and is likely to continue in the foreseeable future. In consequence there must necessarily be a continuing process of manpower redeployment, retraining and redundancies as old plant is closed down, new plant is commissioned and the Board's manpower is adjusted accordingly.

10.28. Redeployment and redundancy are very sensitive issues and the potential for industrial relations problems arising from the Board's processes of manpower adjustment is great. This has been recognised by the Board and by the trade unions representing its employees, and there is a well-established Procedure for Communication and Consultation on Plant Retirements which was approved by the National Joint Advisory Council (predecessor of the present NJCC) in 1971. The procedure acknowledges the CEGB's responsibility to retire uneconomic plant and affirms its policy to consider the welfare of its employees beyond statutory or contractual obligations of conditions of employment. The Board undertakes to make every effort to provide suitable alternative employment.

10.29. The timetable for consultation and implementation of closures, as put to us by the CEGB, is:

'(i) the Board notifies the trade unions of its detailed proposals for decommissioning about 15–16 months before the proposed decommissioning date;

(ii) informal consultations with the trade unions take place during the course of the next 3–4 months;

(iii) the Joint Co-ordinating Council (for England and Wales) is notified of the Board's intentions;

(iv) a formal announcement is made to the staff concerned a year before the decommissioning date;

(v) consultation with staff and District TU Officers takes place on the implementation of the proposals along the lines indicated in the NJAC procedure;

(vi) the JCC is kept informed about progress.'

10.30. Details of the numbers of staff affected by closures since 1972–73 are shown in Table 10.2. Experience has proved that industrial staff are less mobile than non-industrial staff and therefore a higher proportion of the former group prefers voluntary severance. Since 1972 some 5,200 staff have accepted redundancy and more than 2,500 have been redeployed.

10.31. The present severance arrangements were introduced mainly to facilitate the substantial closures programme announced in 1975. Selected staff accepting voluntary severance receive a payment additional to their entitlement under the Redundancy Payments Act. This additional payment is related to age, length of service (maximum 20 years) and weekly earnings. In recent years a high proportion of those accepting severance have also been selected by the Board to receive an early pension (minimum age 55). The average payments made in 1980 under the statutory redundancy arrangements and the Board's own voluntary severance scheme (based on a CEGB sample of 60 cases) were £2,600 and £8,200 respectively.

10.32. The severance arrangements are also used to create vacancies at continuing locations into which staff in decommissioning stations can be redeployed. This helps to preserve a balanced age structure and mix of skills. A new redeployment allowance has recently been introduced primarily to

TABLE 10.2 **Power Station Closure Programmes**

Year of Closure	Capacity MW	Estimated Number of Staff Affected (at time of notification) NJM	NJB	NJC	NJIC	TOTAL	Situation after Closure: Number of staff actually affected	Number accepted severance*	Number redeployed*	Others†	Unresolved‡
1972–73	530	—	112	42	650	804	801	335	212	181	73
1973–74	412	1	56	23	280	360	336	160	129	47	—
1974–75	500	—	20	4	266	290	265	88	19	60	98
1975–76	811	2	114	35	855	1,006	945	601	225	111	8
1976–77 (Oct 76)	2,884	19	607	181	3,288	4,095	4,228	2,805	1,272	151	—
(Mar 77)	535	7	147	62	754	970	818	623	173	22	—
1978–79	737	—	113	45	640	798	663	436	158	62	7
1979–80	269	2	55	21	290	368	464	23	274	145	22
1980–81	630	3	101	39	453	596	596	224	149	64	159
1981–82	3,402	13	487	205	2,398	3,103	NOT YET AVAILABLE				

Source: The CEGB

Notes:
* These figures include those already declared redundant/redeployed and those expecting redundancy/redeployment at the time the statistics were collected.
† The category of Others includes those who retired, resigned or died and a small number retained on site to carry out residual duties.
‡ Information on the staff whose situation was unresolved after the closures of 1972–73, 1974–75 and 1975–76 is not included in HQ records.

encourage mobility of skilled craft and operational staff who might otherwise have left the Board's employment with an entitlement to a statutory redundancy payment. It provides for payments up to a maximum of £1,200 spread over two years, for selected employees in stations being decommissioned who accept redeployment to a specified post at another location without a move of home and without promotion.

10.33. The Board's proposals for plant decommissioning in October 1981, involving the decommissioning and closure of 16 stations and the decommissioning and placing in reserve of a further six, have been discussed with the unions both informally and in the JCC(EW), and the implications for staff are the subject of continuing discussions. The total number of employees affected will be approximately 3,100, including some 2,400 industrial staff. For staff who cannot be offered redeployment, the Board has given its usual undertaking that there will be no compulsory redundancies for a period of 12 months from October 1981 (the statutory notice period is subsumed in the 12 months' notice of closure). The unions have not opposed the closures. The EETPU, for example, accepts that there must be closures but they are seeking a longer timescale for implementation and increased opportunities for redeployment, retraining, etc.

Utilisation of Manpower

10.34. This section considers the CEGB's performance in using its manpower efficiently and minimising its labour costs. The section begins with an examination of the Board's achievements in improving output per head. This is followed by an examination of the Board's labour costs and the section concludes with a discussion of the cost of labour per unit of output in the CEGB.

Output per head

10.35. Table 10.3 shows the growth in output per head in the electricity supply industry and the whole economy (as defined in note 2 to Table 10.3) since 1965–66. It can be seen that the ESI has made more rapid improvements than the economy as a whole. The Area Boards appear to have done better than the CEGB; but if Area Boards' staff are excluded who are not concerned with the distribution of electricity but are engaged in electrical contracting and sales of appliances, the percentage increase in productivity since 1970–71 (the period for which such figures are available) is about 38 per cent in each part of the industry. In both parts of the industry the growth of productivity has been less rapid since 1974–75 than it was before, as growth in electricity sales has slowed down. The Board estimates that over the next five years, as new power stations are commissioned and older stations with larger staffs are closed, output per head as measured in Table 10.3 will rise by 18 per cent.

10.36. The 75 per cent improvement in output per head in the CEGB expresses the combined effects of a 49 per cent increase in the total number of GWh supplied per year between 1965–66 and 1979–80 and a 20 per cent reduction in the Board's total labour force over the same period. The

TABLE 10.3 **Growth of output per head, indices 1965–66 to 1979–80 (1965–66 = 100)**

	Electricity industry			*Whole economy*
Year	*GWh supplied/ CEGB employee*	*GWh sold/ Area Board employee*	*Year*	*Output per person employed*
1965–66	100	100	1966	100
1966–67	95	102	1967	104
1967–68	99	112	1968	112
1968–69	108	126	1969	115
1969–70	118	141	1970	117
1970–71	127	155	1971	121
1971–72	137	165	1972	127
1972–73	155	184	1973	134
1973–74	154	187	1974	130
1974–75	158	198	1975	128
1975–76	155	195	1976	134
1976–77	164	201	1977	140
1977–78	171	213	1978	145
1978–79	177	222	1979	150
1979–80	175	226	1980	149

Source: The CEGB and The National Institute Economic Review.

Notes:
1. The whole economy data are for June of each year.
2. The whole economy data include all manufacturing, construction, gas, electricity and water.

TABLE 10.4 **Numbers employed in the CEGB (including trainees) 1966–80 (as at 31 March)**

Year	*NJM*	*NJB*	*NJC*	*NJIC*	*Total*
1966	616	14,487	8,205	53,328	76,836
1967	796	15,231	8,512	55,650	80,189
1968	840	15,584	8,412	55,084	79,920
1969	812	15,426	8,031	52,148	76,417
1970	797	15,012	7,859	49,227	72,895
1971	775	15,040	7,832	46,638	70,265
1972	760	15,181	7,896	41,573	65,410
1973	780	15,179	7,674	40,131	63,764
1974	774	15,237	7,784	40,422	64,217
1975	798	15,773	8,374	41,154	66,099
1976	795	15,835	8,121	38,461	63,212
1977	755	15,415	8,070	36,493	60,733
1978	793	15,218	8,138	36,542	60,691
1979	786	15,463	8,199	37,261	61,709
1980	817	15,759	8,094	37,056	61,726
		Percentage change for given periods			
1966–80	+0·1	+9	+3	−31	−20
1970–80	+2·5	+5	+3	−25	−15
1975–80	+2·4	−0·1	−3	−10	−7

Source: The CEGB.

reduction in the labour force is shown in Table 10.4, broken down by the four major negotiating groups. It is apparent that the manpower reduction over the 15 year period is almost entirely due to a 31 per cent reduction in the industrial (NJIC) staff. There was no significant change in the numbers of managerial (NJM) and administrative and clerical (NJC) staff, and the numbers of scientific and technical (NJB) staff increased by nearly 10 per cent between 1966 and 1980. The numbers of NJM, NJC and NJB staff were generally higher, but the number of NJIC staff was generally lower, during the second half of the 1970s than during the first half.

10.37. *NJIC staff.* The reduction in the numbers of industrial staff over the past 15 years stems from the application of more advanced technology, particularly in the new power stations commissioned during the period, and from productivity agreements negotiated in the late 1960s.

10.38. The following table shows, at constant 1980 price levels, the increase in gross generation assets per employee over the period 1966–67 to 1979–80:

	£'000 (1980 prices)
1966–67	20
1967–68	21
1968–69	23
1969–70	26
1970–71	28
1971–72	32
1972–73	36
1973–74	38
1974–75	38
1975–76	38
1976–77	39
1977–78	39
1978–79	39
1979–80	39

The doubling in the value of assets per employee reflects the introduction of large generating sets in the new stations commissioned over the period. This has contributed to the improvement in output per head discussed in paragraphs 10.35–10.36. These were introduced mainly to save fuel rather than labour costs, but there have been consequent changes in working practices which have been accepted and implemented in the power stations with a minimum of industrial relations difficulties. The way for this was opened by a series of important collective agreements in the late 1960s which conditioned attitudes to productivity through the 1970s.

10.39. Output per head was low in the early 1960s, excessive amounts of overtime were being worked, particularly at weekends, and the relative basic pay levels of industrial staff were below the national average. However, far-reaching productivity agreements reached between 1964 and 1968 introduced staggered working patterns, work measurement and productivity payment schemes. The staggered work patterns allowed the Board to relate the work patterns of staff to the work which had to be undertaken, with evenings and weekends treated as part of the normal working week. As a result, 96 per cent of NJIC staff are now involved in some form of shift or staggered work pattern. Before the introduction of staggered working (eg any five days from seven) weekly hours worked in electricity generation averaged 53 per man. The new work patterns greatly reduced the need for overtime and by 1970 the weekly average hours had reduced to 41. They have since risen to 43 per week.

10.40. The acceptance of work measurement and productivity payment schemes transformed the industry. Industrial consultants engaged by CEGB in the mid-1960s estimated that the existing work rate norm for the industry's industrial staff was only about 60 per cent of 'standard performance'[1]. The CEGB has told us that by the end of the 1970s around 99 per cent of its industrial workforce were achieving 'standard performance'. The CEGB's management believes this to be the best available measure of the productivity of NJIC staff. Performance is continuously monitored and reviewed jointly by management and the unions at frequent regular intervals. The Board has over the years built up an extensive data bank of measured work, particularly for engineering assembly and maintenance. Some indication of the Board's competence and reputation in this area is provided by its record of success in marketing its data and systems both in the United Kingdom and overseas. Income from these activities had reached £350,000 at 31 March 1980.

10.41. Workforce pressures have built up in recent years for extra payments to be made in recognition of performance above the standard. The Board was reluctant to move in this direction fearing that the validity of the standards would be undermined. The industry, through the NJIC, preferred to move in 1979 to what they viewed as a further stage in the implementation of staff status by the consolidation of bonus payments and there has since been no direct financial incentive to maintain or improve productivity. The time standards and the recording and monitoring systems are still operative, but the removal of the financial incentive has inevitably put increased pressure on supervision and management to ensure that there is no slippage in performance. The Board's monitoring indicates that, apart from power stations on the closure programme, there has been none so far. Should slippage occur, there are procedures under the NJIC agreement for investigating the reasons and taking corrective action.

10.42. Flexibility of working among NJIC staff is a feature which has distinguished the electricity generation industry from many others. Clause 202 of the NJIC Agreement introduced in 1967 reinforced earlier provisions on employee co-operation. It provided for a good measure of the flexibility which is essential to efficient performance. It recognised management's responsibility to change organisation and methods, to apply the results of work measurement, and generally to promote the efficient use of industrial staff. In particular, it permitted, subject to consultation:

(1) use of craftsmen for associated work within their competence;

(2) use of higher grade staff on lower grade work;

(3) temporary up-grading;

(4) cross-posting of plant operators and attendants;

(5) mobility within and between local management units.

[1] 'Standard performance' (as defined by the British Standards Institution) means the rate of output which qualified workers will naturally achieve without over-exertion as an average over the working day or shift provided they know and adhere to the specified method and provided they are motivated to apply themselves to their work. This performance is denoted by 100 and corresponds to the production of one standard hour of work per hour.

The extent of flexibility achieved has inevitably varied by location but overall the increased flexibility of working by industrial staff has made an important contribution to the improvement in output per head secured by the Board over the past 10–15 years.

10.43. In January 1981 a new salary structure was agreed for NJIC staff, replacing more than 100 different narrowly designated grades by five broad salary bands. This development has come too late to be considered in our report.

10.44. *NJB staff.* There has been no reduction in NJB manpower in the last 15 years; indeed, their numbers have grown. Among the factors which have increased the Board's requirement for scientific and technical staff since 1966, are the growing technical complexity of the processes and plant employed, the increased sophistication and wider use of management control systems including the management of the NJIC productivity payment schemes, the large numbers of NJB staff involved in commissioning new power stations, and the increased emphasis on research including the development of alternative power sources (eg wind, wave and solar power).

10.45. We detect, however, some evidence of overgrading, and some indications of obstructive attitudes to change. Some of the duties performed by junior engineering grades, for example, are more appropriate to the supervisory or craftsmen grades and it may be better to introduce a new category of technician grade to undertake an intermediate range of functions between the industrial and engineering grades. We note that the CEGB is aware of the issue. There is also some overgrading of work currently performed by some second engineers as a consequence of the 1974 Trained Engineer Agreement which provides for automatic progression from third engineer. The industry first took the initiative in seeking the introduction of job evaluation for engineers in 1974, but negotiations with the EPEA have still to be brought to a successful conclusion some six years later. Similar long delays have attended consultations with the EPEA on the re-organisation of technical staff structures in large power stations.

10.46. *NJC staff.* There has been only a small reduction in the number of NJC staff since 1966. Some of the factors which have made for an increase in NJB staff are likely to have had a similar effect on the requirement for professional and administrative staff. Clerical work measurement has been in use in CEGB offices since 1972 and has produced some decrease in junior NJC staff although not to the same extent as NJIC staff. A code of practice on the introduction of automated and new equipment was agreed by the NJC in 1978 and the CEGB expects to achieve some further reduction in staff numbers through the introduction of technological change. In order to achieve short-term economies the Board is currently seeking a reduction of 5 per cent in National and Regional head office staffs by March 1981.

10.47. *NJM staff.* The Board's management staff are located chiefly in the National and Regional head offices. They represent only about 1 per cent of the CEGB's total staff. While the numbers of NJB staff have increased over the past 15 years the numbers of NJM staff have remained relatively stable, though somewhat higher in the late 1970s than in the earlier years of the decade. Among the Regional staff we have noted that there are a number of staff designated as Group Managers who in practice have no formal executive power. The origin of their role is clear: they acted in a co-ordinating capacity, as an extension of the Directors of Production in an era when there were too many production units for easy communications. However, since the number of stations is decreasing and the status of the managers of large stations which increasingly predominate is growing, there may in future be opportunities for some reduction in the number of Group Managers.

Labour costs

10.48. Pay and conditions of employment generally in the CEGB compare well with those of other employers, in both the private and the public sectors. This reflects the high proportion of NJIC staff who are skilled (56 per cent), the complex technology involved and the high extent of 'unsocial hours' working (20 per cent of NJB staff work shifts and 96 per cent of NJIC staff work shift or staggered work patterns). There has also been, over the past 15 years, an enlightened programme of harmonisation of conditions between industrial and non-industrial staff. This 'staff status' programme, which has been aimed at improving morale, motivation and flexibility of NJIC staff, has included the introduction of annual salaries, improved sick pay and pension schemes and enhanced holiday entitlements. Even so, labour costs have represented a decreasing proportion of the Board's total costs, falling from over 12 per cent in 1965–66 to under 10 per cent in 1979–80, partly as a consequence of rising fuel costs.

10.49. Trends in the average earnings of the Board's staff over the past 15 years are shown in Figure 10.1, which shows the earnings of NJM, NJC, NJB and NJIC staff relative to the national average for all employees. It is evident that NJM staff have lost ground compared with the national average since 1966–67 but have improved their relative position since 1977–78. There is little clear evidence of any similar long-term change in the positions of NJB, NJC and NJIC staff relative to the national average for all employees.

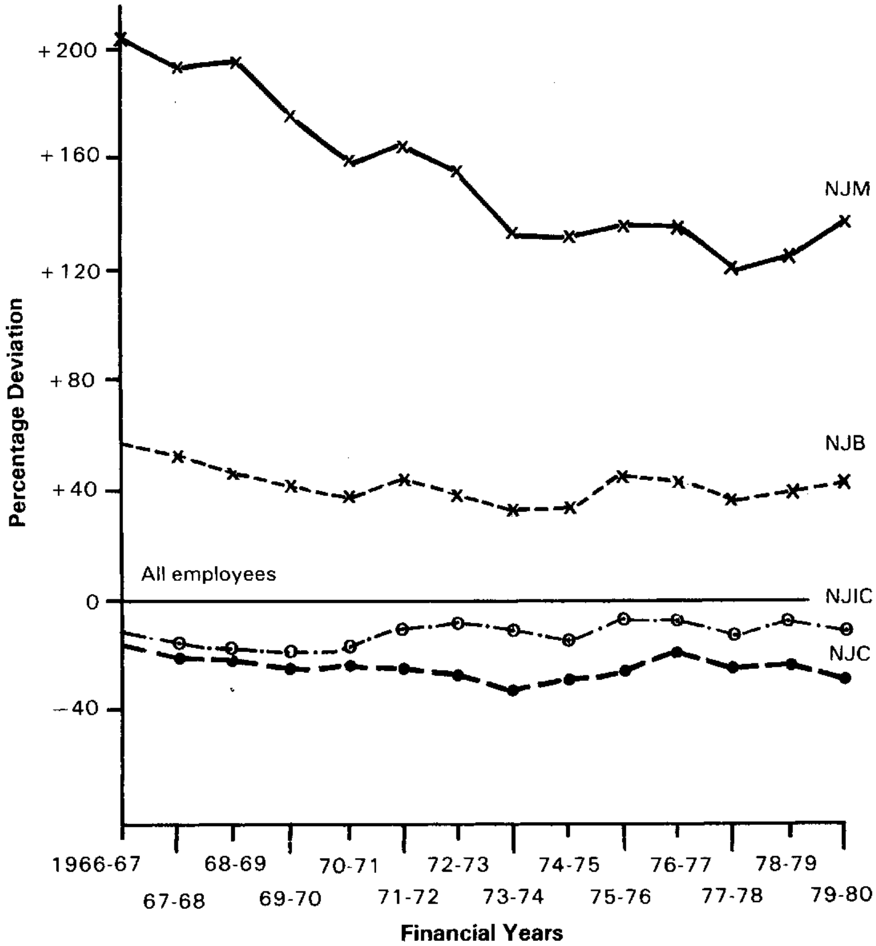
10.50. *NJIC pay.* Figure 10.2 shows that the average weekly earnings of CEGB industrial staff remained below the national manual average until 1971. Their relative position continued to improve during the 1970s, however, and by 1979 their weekly average earnings stood almost 25 per cent above the national average for all manual employees.

10.51. *NJB pay and allowances.* Figure 10.3 shows the recent trends in the average weekly earnings of NJB staff and all electrical and electronic engineers compared with the average for all adult male employees. It is evident that the earnings of the NJB staff have been maintained at a level above those of other electrical and electronic engineers over the past five years. NJB earnings have been rising relative to the average for electrical/electronic engineers since 1978. In 1980 they stood higher relative to this group than at any other time in the past eight years.

FIGURE 10.1

Percentage Deviation of average earnings of NJM, NJB, NJC and NJIC from the average earnings of employees in all Industries and Services

[*Manual and non-manual men aged 21 and over*]

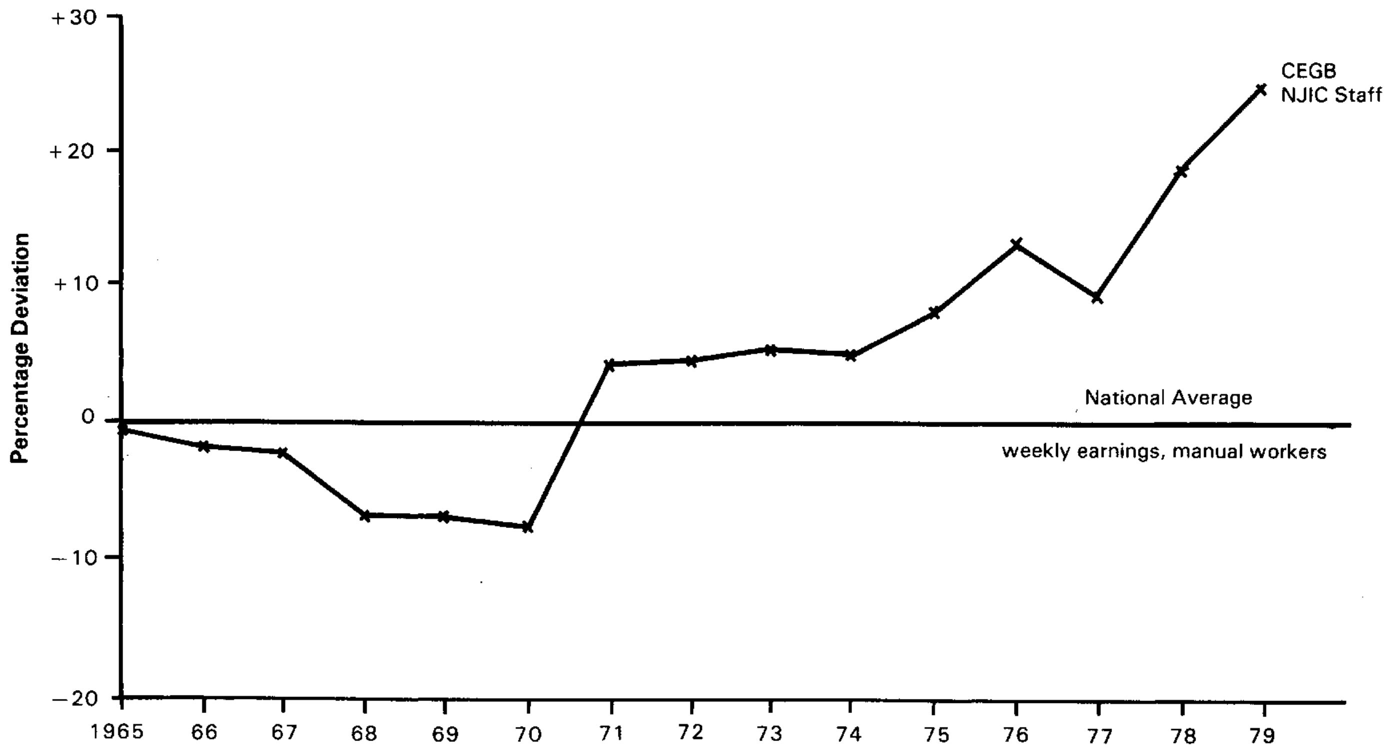


Sources: The CEGB, New Earnings Survey, Department of Employment.

Notes:
1. Data include overtime pay.
2. Data for all employees in all Industries and Services have been projected backwards prior to 1970 using monthly average earnings indices which cover all employees in production industries, transport (except sea), agriculture and a few miscellaneous services.

FIGURE 10.2

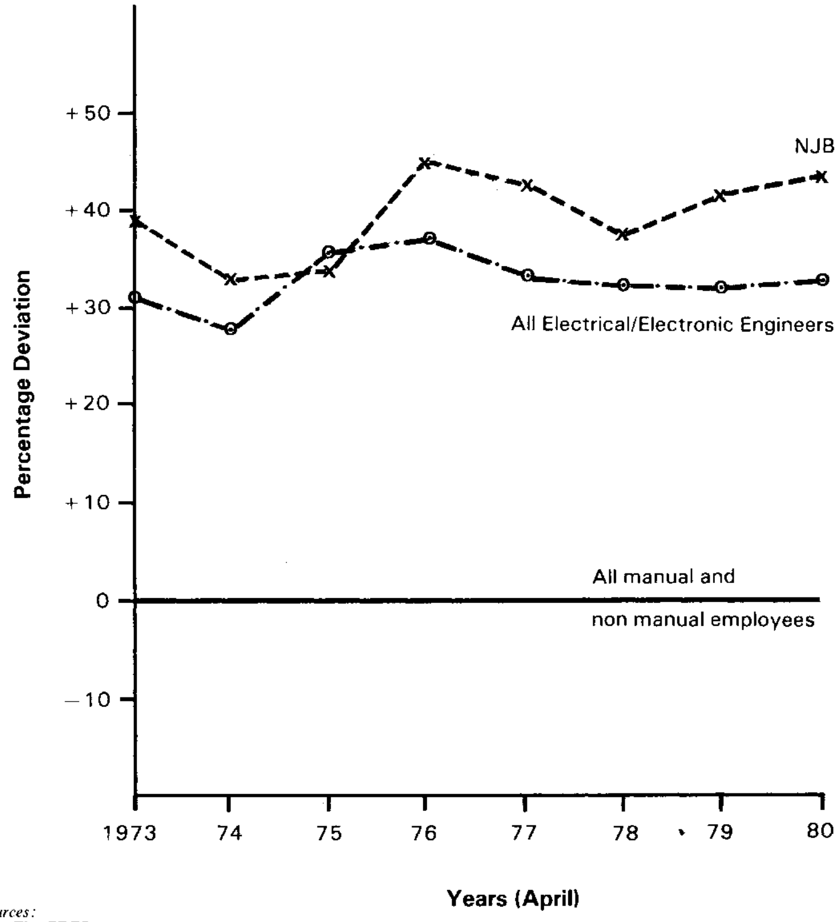
Percentage Deviation of the average weekly earnings of CEGB NJIC Staff from the National Average for manual workers



Sources: The CEGB and Department of Employment.

FIGURE 10·3

Percentage Deviation of gross average weekly earnings for CEGB NJB staff and Electrical/Electronic Engineers from all manual and non-manual employees in all Industries and Services



Sources:
1. The CEGB.
2. New Earnings Survey, Dept of Employment.

Note: Data are for full-time men aged 21 and over whose pay was not affected by absence.

10.52. Part of the explanation of the increase in average NJB earnings appears to be a shift in the balance of numbers by grade from the lower to the higher grades. This is illustrated in Table 10.5; there was little or no change in the total of NJB staff over the period shown. This shift in the numerical balance of the grades can partly be explained by the traditional linking of the grading of NJB posts in power stations with the size of the stations. Thus, as the Board has closed smaller stations and commissioned larger ones there has been a decrease in the proportion of lower graded posts. When job evaluation for NJB staff is introduced the CEGB intends to abandon grading according to station size. Another factor affecting the numbers by grade has been the restructuring of Regional headquarters and the establishment of a number of specialist posts to advise power station management, requiring the appointment of high calibre staff. The shift in numbers between Third Engineer and Second Engineer is also due in part to the 1974 Trained Engineer Agreement which provided for such progression by appropriately qualified and trained staff.

TABLE 10.5 **Distribution of NJB staff by grade 1975 and 1979**

Classification	*Percentage distribution by grade* 1975	1979	*Percentage change in nos in each grade 1975–1979*
Principal Engineer	2·81	3·11	+10·66
Senior Engineer	10·57	11·72	+10·68
First Engineer	22·98	26·26	+14·09
Second Engineer	34·77	36·70	+ 5·39
Third Engineer	25·53	19·51	−23·69
Engineering Assistant	3·36	2·69	−20·09
TOTAL	100·00	100·00	

Source: The CEGB.

10.53. *Car allowance.* The CEGB has a number of staff who, because of the remote location of many power stations, transmission lines and substations, and the nature of their work, have to use their own cars to carry out the Board's business. Such staff are paid a car allowance in accordance with the agreement negotiated nationally for the industry. Those classified as regular private car users are entitled to have the road tax and insurance costs of their vehicles paid by the Board. In addition they are paid 75 per cent of the AA figures for other standing charges (ie interest on capital, depreciation and garaging) partly as an annual allowance paid in 12 monthly instalments ranging from £34·50 to £62·00 per month, and partly as a component of the mileage allowances paid on a scale from 10·43p–16·34p per mile depending on the engine capacity of their cars. Staff classified as casual users who are required to make occasional journeys on official business receive a mileage payment only on a scale from 18·14p–28·88p per mile up to 7,500 miles per annum after which the rates fall to the regular user rates. The CEGB has told us that it recognises that the cost of motor travel is high and it therefore operates strict control of its use by the authorisation of journeys, by limitations on the number of staff who are authorised to use their own cars, by insistence that staff use public transport where this is more economic, and by the provision of alternative arrangements where appropriate.

10.54. *Standby and Call-out.* Staff who are required in accordance with a pre-arranged rota to undertake standby duty outside normal working hours by remaining on call within a reasonable distance of their home in order to give advice and/or be called out in an emergency are paid a fee of £37 for each week of standby. In the year ending 31 July 1979 (the latest date for which collated annual figures are available) there were 8,975 weekly standby fees paid to NJB staff; on average therefore about 173 NJB staff are on standby each week covering all the CEGB's activities. In the same year there were 23,784 call-out payments made to NJB staff. Detailed figures for the number of call-outs per employee on standby are not available, but the CEGB estimates that there are about two call-outs per individual for each week of standby duty.

10.55. Other employers of electrical and electronic engineers have told us that they have experienced difficulty competing with the terms and conditions of employment which the electricity supply industry has been able to offer in recent years. They have laid particular stress on the relatively greater security of employment which has existed for engineers employed by the industry.

10.56. *HJM/NJB differentials.* In recent years the NJM salary scales have become compressed; they have been kept down at the upper end by Government restrictions on pay at the topmost levels of the industry, while at the lower end they have been forced up by the relative increases in NJB salaries, which, since an arbitration award in 1979, are linked to a fixed point of the NJIC scales. As a consequence the differentials between the managerial grades have been reduced—the current extent of overlap and the limited differentials between the grades is shown in Table 10.6. As regards the NJM/NJB differential, there is for example in practice often a reverse earnings differential between the power station manager and his more senior engineers on shift allowance. This reverse differential can extend up into the ranks of Regional Chief Officers and leads sometimes to a reluctance of senior engineers on shift allowance to accept promotion.

TABLE 10.6 **NJB and NJM salary structures**

Engineering Assistant	£5,085– £7,985
Third Engineer	£5,925– £8,965
Second Engineer	£7,985–£10,600
First Engineer	£9,215–£12,805
Senior Engineer	£10,905–£14,070
Principal Engineer	£13,645–£15,815
Band I	£10,700–£13,340
Band II	£11,930–£14,740
Band III	£14,270–£16,500
Band IV	£15,210–£17,350
Band V	£16,500–£18,350
Band VI	£17,350–£19,150
Band VII	£18,250–£20,050
Band VIII	£19,600–£21,050

(NJB with effect from 1 February 1980)
(NJM with effect from 1 April 1980)

Source: The CEGB

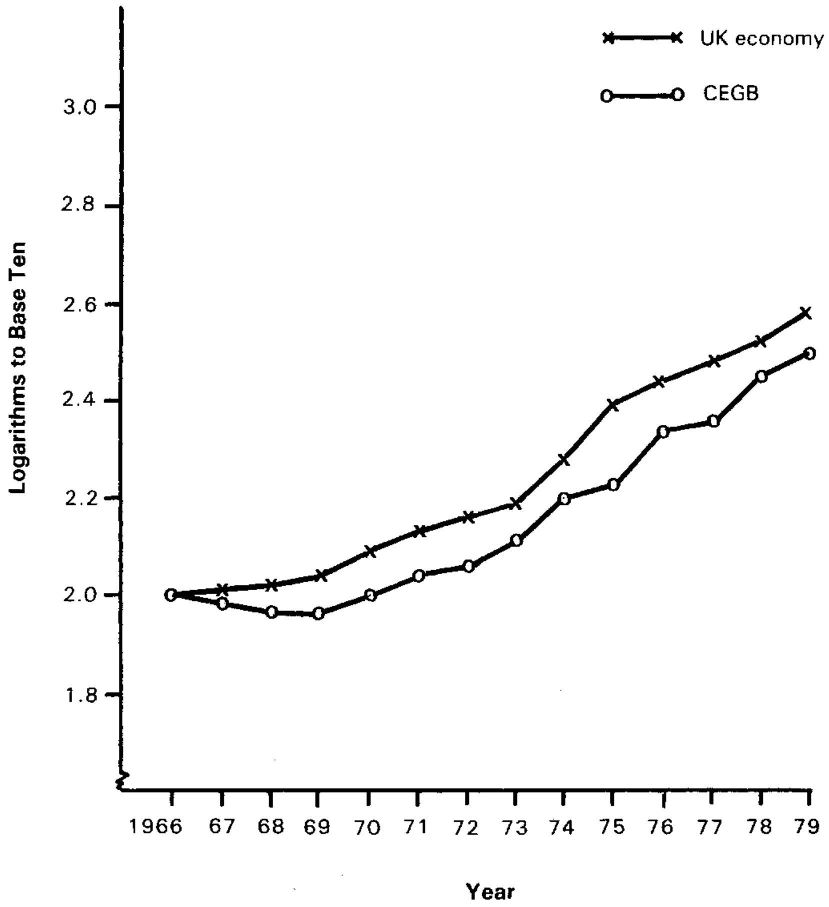
Note: An allowance is payable to engineers who work shifts. It varies from £1,490 per annum for an engineering assistant to £3,065 per annum for a principal engineer at the top of his scale. Similar allowances are payable to NJC staff.

The Relationship between Labour Costs and Output per head

10.57. Table 10.7 (page 229) shows that over the 15 years from 1965–66 to 1979–80 output per head in the CEGB improved by some 75 per cent while real total labour costs increased by 62 per cent. Over the last ten years, however, output per head grew by 38 per cent compared with a 46 per cent increase in real total labour costs but this trend was not maintained during

FIGURE 10.4

Logarithmic graph to base 10 of the Indices for Labour Costs per Unit of Output for the CEGB and the UK



Sources: The CEGB and Dept of Employment

Notes:
1. The CEGB—Labour cost per GWh for the financial year—eg 1966 = 1966–67.
2. UK economy—Labour cost per Unit of Output—average for the calendar year.
3. UK economy = Orders I–XXVII of the UK Standard Industrial Classification of the Central Statistical Office.

the most recent five years, when the respective figures were 13 per cent and 8 per cent. The CEGB has told us that delays in commissioning new stations and the consequently higher staffing numbers, both in stations not yet commissioned and in those which cannot be decommissioned have restrained the bigger increase in output per head which would otherwise have been possible. The Board has estimated that the commissioning of new power stations over the next five years, together with the decreases in manning levels which will result, will further increase output per head by some 18 per cent.

TABLE 10.7 **Output per head and real labour costs in the CEGB, 1965–66 to 1979–80**

	Percentage increase	
	GWh supplied/employee	*Real labour costs*
1965–66 to 1979–80	75	62
1970–71 to 1979–80	38	46
1975–76 to 1979–80	13	8

Source: The CEGB

10.58. Another useful measure of labour costs and the efficient use of manpower is the cost of labour per unit of output. Figure 10.4 compares the CEGB's performance with the economy as a whole, showing that over the period 1965–66 to 1979–80 unit labour costs increased more quickly in the economy as a whole than in the CEGB, although its unit labour costs have been growing faster than those of the whole economy over the past two years.

Conclusions

10.59. The CEGB personnel function is well organised and co-ordinated. Progressive policies on staff training and the harmonisation of terms and conditions of employment have been pursued. Labour turnover and absence rates are generally low and there are few recruitment problems. Such problems as have emerged have been clearly identified and studied and suitable remedial action has been set in hand.

10.60. Industrial relations are generally good, the machinery for collective bargaining and joint consultation works well and there are few strikes or other forms of industrial disruption. The move towards a Joint Negotiating Committee, which would bring all the trade unions together at national level, is to be welcomed as a means to further simplifying and co-ordinating the industry's somewhat complex negotiating structures. The current reorganisation of the CEGB's district and local consultative machinery should also assist towards simplifying the system and making it more responsive to the needs of the management and staff.

10.61. Two of the more sensitive industrial relations issues, particularly at a time of high unemployment, are the use of contract labour and the closure of life-expired plant. The jointly agreed guidelines which have been established for discussions on contract labour have helped to ensure that the issue has not been a significant cause of industrial disputes. There is nevertheless a continuing need for minimisation of the additional labour costs arising from the Board's policies in this area.

10.62. The periodic need for decommissioning of redundant power stations is accepted by both management and staff in the industry. The jointly agreed procedure for handling plant retirements has worked very well in the past and is currently facilitating a major new phase of essential closures.

10.63. The Board's overall achievements in increasing output per head are very largely due to a 30 per cent reduction in NJIC manpower, improvements in flexibility of working practices, reduced overtime working and the introduction of work measurement and bonus incentives. However, over the past few years overtime has shown some signs of creeping up and the bonus incentive scheme has recently been consolidated. Responsibility for the efficient use of manpower rests primarily with management and it is important that they should not allow the momentum for improvement in output per head by NJIC staff to be lost. The CEGB must keep the situation very closely under control and be ready with a strategy for maintaining and further improving the levels of NJIC efficiency.

10.64. The improvements in output per head are also due in part to the contribution of NJB staff. We have, however, found evidence of overgrading amongst NJB staff, and indications of reluctance to accept and co-operate in rationalisation of their grading structures. Negotiations for the introduction of job evaluation for engineers have been going on since 1974 and no conclusion has yet been reached in this field of such importance for the future of the industry. We think it would be helpful if management were to tie negotiations to a timetable for their completion and the introduction of the new scheme. While we have no clear evidence of over-manning in NJB work, we believe it is important for the future success of the industry that NJB staff should co-operate, and be seen to be co-operating, in measures to improve the efficiency of their utilisation and deployment.

10.65. There has been little change in the numbers of NJC staff over the past 15 years. We note the Board's present intention to seek a reduction in Head Office staffs with a target of 5 per cent by March 1981. We believe there is likely to be further scope for greater efficiency of NJC manpower utilisation and we recommend further implementation and extension of the established clerical work measurement systems and the application of modern office technology.

10.66. The numbers of NJM staff have also remained fairly stable over the years. We anticipate, however, that there may be scope for some reduction in their numbers as the generation of electricity is concentrated in a smaller number of large power stations. In particular, we consider that it will be appropriate for the Board to review the need for the continuing inclusion of Group Managers in its organisation structure. In general, we consider that there may be too many grades in the NJM hierarchy and that simplification of the structure would help to ease the problems caused by compression of the salary scales in recent years.

10.67. We have noted that the Board makes substantial use of employees' private cars for official business, and that it reimburses them on a scale which is more generous than many other employers provide. We note the Board's assurances that it operates strict controls on the official use of private cars. We consider that it should also explore the possibilities for reducing the costs that must necessarily be incurred, for example through the provision of official cars or by contract-hire arrangements.

10.68. We commend the Board's achievements in improving the quantity of electricity generated per head over the past fifteen years. In recent years, however, the rate of improvement has slowed appreciably, while at the same time the CEGB's labour costs have been rising more rapidly than the national average. In consequence the Board has been less successful recently than hitherto in containing the rate of increase in its unit labour costs. These trends serve to emphasise the need, therefore, for the Board and all the trade unions in the industry to co-operate in securing further improvements in the efficiency with which the industry's manpower is used at all levels. This will help to limit future increases in the price of electricity which consumers will have to pay because of other factors discussed elsewhere in this report.

CHAPTER 11

Management Information Systems

Introduction and the Concept of MIS

11.1. In Chapter 6 we examined the Board's operational planning and noted the overall nature of the system for generating and distributing electricity. In this chapter we consider management information in the same light as an overall system. The function of a Management Information System (MIS) is to provide the decision-maker at all levels of management with the best information available to the organisation appropriate to the nature of the decision for which the particular manager is accountable. The design of an MIS aims at overall optimisation in the context of the total organisation.

11.2. An MIS normally acts as an aid to three categories of management activity:

(a) *Strategic planning*, which is the process of deciding upon the objectives and determining the level of resources by formulating policies for the acquisition and disposition of resources. In the case of the CEGB the time horizon is between one and about ten years. The first five years are covered by their operational planning and the longer term by their investment planning. Both attempt to integrate across the Board's activities.

(b) *Management control*, which is the process by which managers ensure that resources are obtained and used effectively in achieving the organisational objectives. The control is split between general management and functional management. The main activities are the allocation of resources and the formulation of rules for operating and the measurement of performance. The CEGB's time horizon is usually less than one year.

(c) *Operational control*, which is the process of ensuring that specific tasks are carried out effectively. The main activity is the use of resources to carry out tasks in conformity with the rules. The function is concerned with the control of the day-to-day activities of the organisation.

11.3. The general trend is for the core of MIS to be based on computer systems supported by data bases, ie systems of primary data organised in such a form that they are immediately usable in any part of the organisation.

11.4. The information made available at each level of management should be specific to that level and supplied at appropriate intervals. The information is normally organised into reports of three types:

(a) *Regular reports.* These are summaries of the current state of the system. They are mainly descriptive and keep managers informed of the general progress of that part of the organisation for which they are accountable.

(*b*) *Exception reports.* These are reports triggered by performance deviating from an acceptable level and they call for action.

(*c*) *Special reports.* These may be ad hoc and often the result of enquiries of an exploratory nature. The information may be the output of an associated simulation or optimisation model.

11.5. Although we have found the Board's management systems well organised and well supplied with information and containing many of the characteristics outlined above there is no common national structure relating to a centrally designed Management Information System. The special features of the CEGB which give rise to this are discussed below.

11.6. In the rest of this chapter we discuss, in turn:

—the characteristics of the CEGB information structure;

—historical initiatives on MIS;

—the outline of the main information systems;

—the level of computing support for MIS;

—developments towards a centralised policy for management systems.

The Special Characteristics of the CEGB's Information Structure

11.7. We have noted that there is no common national structure to the management information throughout the CEGB which could be understood as an integrated system. There are clear reasons for this, some of which are peculiar to the nature of the industry and some of which result from deliberate policy.

11.8. First, the Board has adopted a policy of devolved management accountability. The management style is to decentralise and to push accountability as close to the working level as possible. Thus Regions and locations (power stations and transmission districts) have a great deal of autonomy. In the main the local managers develop their own Information System for their own needs as they see them. Indeed each manager is responsible for seeing that he gets the information he needs for taking the decisions for which he is accountable. In addition there are some clearly defined and documented requirements in use throughout the CEGB.

11.9. The second characteristic is that since the technical base of the industry is well understood, many operational decision areas can be simulated or modelled with a high degree of accuracy. The consequence is that many routine decisions are set out in the form of model outputs or are embodied in procedures which set out the recommended action to be taken on the occurrence of a particular event. This leaves local management with the task of exercising its judgment on the recommended action. Examples of this are to be seen in the use of the SYMAN suite, the transmission assessment programs, the reactor physics programs and the resource scheduling and control programs such as PERT and SMART.

11.10. A third factor related to the above is that many of the information flows contain very detailed data which are required for input to the computer models. The use of computer models at all levels constrains the amount of condensation and filtering that can be applied to prime information. An additional complicating factor is that not all Regions or locations use the same models, except in critical areas.

11.11. The final factor relates to the magnitude of decisions that can be taken at all levels. In the CEGB, as in other organisations, most decisions with significant cost consequences are taken at Board and HQ level. But it is also inevitable that decisions made during operational shifts at station, Area and National Control level by shift personnel, within the limits of delegated authority, will have major cost consequences.

11.12. Shift charge engineers may be faced with occurrence of a fault on a set or reactor and have to decide whether to off-load the set to start immediate repairs or to reduce load and delay repairs until routine maintenance can be programmed. These decisions have significant cost implications, for example the outage cost of a 500 MW coal-fired unit is about £50,000 a day, and for a 500 MW reactor about £170,000 a day. Controllers may also be faced with decisions to disconnect users on the occurrence of faults. The disconnection of supply has a very important effect on revenue. In all cases the shift personnel will make their decision in the light of the commercial, technical and security of supplies consequences.

11.13. The magnitude of the decisions which must be made at operational level has the effect of reducing the hierarchical decision structure compared with many other organisations.

Historical Initiatives on Management Information Systems

11.14. The Board has recognised the need to improve management systems at Regional HQ and power stations. In particular it wishes to reconcile devolved management policy with the need to take commercial decisions in a national context and hence the desirability of an integrated MIS. The Board has made several attempts to deal with the problem and these are set out in Appendix 18.

11.15. Many of the Board's initiatives made little progress but three nationally implemented systems have resulted:

Payroll and personnel statistics — developed in the NE Region associated with a national working party in 1963 and implemented throughout the Board.

Fuel accounts and statistics — developed in the Midlands Region, also associated with a national working party in 1963, and fully implemented nationally.

The standard form of budget monitoring — developed as the result of the Chairman's recommendation in 1970.

11.16 Since the middle 1960s a number of further systems have been developed and implemented nationally on the initiative of HQ chief officers or of the Regions. Examples of initiatives by chief officers are:

Station thermal efficiency performance (STEP) — developed in the early 1960s by a Board working party chaired by the Chief Operations Engineer.

Computer assisted systems operation (CASO) — This is a time-sharing system on a Board-wide computing network based on the Headquarters Computing Centre. The system uses a suite of programs for demand forecasting, network analysis for security assessment and a series of economic operation models (SYMAN). The system was developed at Headquarters but the software is maintained by the NE Region.

Plant reliability/availability (PRA) — this is a generating plant reliability and availability information system. The initial system was defined by a Board working party but the software is maintained by the NW Region.

Examples of regional initiatives which have been co-ordinated for national use are:

Financial information and budgeting system (FIBS) — being developed in the NE region.

Power station work planning real time system (KISMET) — the system encompasses a work data bank and interrogation facility (eg jobs outstanding in plan areas, safety, high priority etc). It enables jobs to be progressed from initial identification through work engineering to printing out of the job card for issue. It also produces a history file for later analysis.

11.17. In addition there have been many regionally developed systems that have seen only partial acceptance nationally. There are several systems under development for Materials Control and Plant Outage Planning.

Monitoring of station commercial operating performance

11.18. We have noted that in the regions there are several different approaches to the problem of providing both Regional and power station managers with information to assist in monitoring the commercial operating performance of stations and in making operating decisions that maximise value for money. In most cases there are panels of representatives from each function chaired by the power station manager. The different variations have been discussed in Chapter 6.

11.19. We have been particularly impressed with a study being carried out in the SW Region. A working group 'The Overall Commercial Appreciation Group' has been set up to develop a reporting system to display the performance of a power station in commercial terms. The objective is to devise a performance measure which relates several engineering targets to financial consequences. It is hoped that this will assist managers at stations to make better decisions about the relative significance of the deviations from the various targets.

11.20. The group has developed the concept of the 'SCOPE' factor (Station Commercial Operating Performance) which is based on the contribution of a power station to the reduction of national fuel costs if all targets were just met. The targets chosen are intended to represent the long-term potential of a station of a certain type and not on any foreseeable short-term problems of particular stations. The definition of the SCOPE factor is given in Appendix 19.

Outline of the Main Management Information Systems

11.21. We have noted that the Board's organisational structure and the policy of accountability have produced management systems that were conceived, designed and implemented by functional management. They are often in the form of procedures which define the role of individuals and govern their actions, such as financial procedures and operational memoranda.

11.22. These functional origins have led to systems frequently having a greater degree of vertical than horizontal integration. We have not been able to see a clearly defined system for general management because this requires horizontal integration which is made difficult by having to cut across functional management accountability. However we recognise that the Directors of Resource Planning and the existence of panels and informal meetings do provide a measure of horizontal integration.

11.23. We have attempted in Table 11.1 to set out the main decision areas of strategic planning, management control and operational control with respect to the organisational structure of the Board. It should be emphasised that some inputs to each of these do occur at all levels in the Board and that the table demonstrates only the relative concentration of importance. The strong links between organisation levels in functional management control and in systems operational control are clear.

TABLE 11.1 **Relationship between Main Decision Areas and Board Organisation**

	Organisational Level			
Level of Control	*Executive*	*HQ*	*Region*	*Station*
Strategic Planning	*	*	*	*
Management Control				
(*a*) General Management	*		*	*
(*b*) Functional Management				
— Systems Ops Planning		*	*	*
— Fuel Planning		*	*	*
— Manpower		*	*	*
— Finance		*	*	*
— Procurement		*	*	*
Operational Control				
— Systems Ops		*	*	*
— Fuel			*	*
— Personnel				*
— Budget				*
— Procurement				*
— Work Control				*

Source: The CEGB

11.24. The specific areas of decisions at Executive, Regional Director General and Station Manager levels are set out in detail in Tables 11.2, 11.3 and 11.4. The tables also indicate the main regularly produced information and monitoring documents, the frequency of reports and the levels of decision in terms of Strategic Decisions, Managerial Control or Operational Control.

TABLE 11.2 **Descriptive Information Flow to the Executive**

Subject	*Information in Report*	*Frequency*	*Control Level*
Corporate Planning	Executive Guidance	Annually	S
	September Outline Plan	Annual Cycle	S
	Determination of Budgets	Annually	M
	Budgetary Process	Annual Cycle	S
Investment	Development Review	Annually	S
	Plant and Load Review	Annually	S
	Preparation of CIM/for Secretary of State	Annually	S
	Progress of power station construction	Monthly	S/M
	Progress of capital spend	Monthly	M
	Approval of major schemes and contracts	Weekly	M
Annual Plans	Research	Annually	S
	Education and Training	Annually	S
	Computing	Annually	S
	National Spares	Annually	S
Operations	Determination of Fuel Programmes	Half Yearly	S
	Determination of Operating Regimes	Half Yearly	S
	Performance Report	Monthly	S/M
	Fuel Stocks and Consumption	Weekly	M
	State of Main Plant	Daily	M
	Incidents Report	Daily	M
Prices	Determination of Bulk Supply Tariff	Annual Cycle	S
	Trading Results	Monthly	M
	Major agreements for supply of by-products	Ad hoc	M
Borrowing	Determination of CEGB share of ESI EFL	Annual Cycle	S
	Progress against EFL	Monthly	M
Costs	Approval of major revenue schemes	Weekly	M
	Progress of revenue spend	Monthly	M
	Costs of production	Daily	M
Personnel	Determination of manpower policies and levels	Annual Cycle	S/M
	Participation in negotiations	Ad hoc	S/M
	Manpower levels	Monthly	M

Source: The CEGB

Note: In addition, the Executive receives a wide range of policy issues presented by Chief Officers on an ad hoc basis, relating to strategic and managerial topics.

S = Strategic.
M = Managerial Control.
O = Operational Control.

TABLE 11.3 **Descriptive Information Flow at Regional Director Level**

Subject	*Information in Report*	*Frequency*	*Control Level*
Operations	Plant and system state	Daily	M
	Severe accidents and dangerous occurrences	Ad hoc	O
	Persistent interruptions of supply	Ad hoc	O
	Progress of overhauls	Weekly	O
	Forecast of plant state for 1 month ahead	Weekly	O
	Summary of performance statistics and inter-regional comparisons	Weekly	M
	Fuel supplies situation	Weekly	O
	National plant/demand trends	Monthly	O
	Regional merit order revisions	Monthly	O
	Operational returns	Annually	O
	Loading programme	Twice a year	O
Costs	Approval of revenue schemes within delegation	Ad hoc	M
	Contract commitment	Weekly	M
	Progress of expenditure against budget and estimated out-turns	Monthly	M
	Budget formulation	Annually	M
	Outline plan forecasts	Annually	O
Investment	Capital budget formulation	Annually	O
	Outline plan forecasts	Annually	O
	Progress of capital expenditure against budget	Monthly	M
	Approval of capital expenditure within delegation	Ad hoc	M
Prices	By-product disposal	Quarterly	O
	Bulk Supply Tariff data for formulation	Annually	S
Purchasing	Contract approval	Ad hoc	M
	Return of contracts and other large orders	Weekly	M
	All proposals concerning purchase of non-British Equipment	Weekly	M
Personnel	General man-management	Weekly	O
	Contractor's performance	Weekly	O
	Internal industrial relations situations and those outside CEGB which may affect it	Ad hoc	M
	Progress against budget manpower levels and targets	Monthly	M
	Budget/out-turn manpower statistics	Annually	M

Source: The CEGB

S = Strategic.
M = Managerial Control.
O = Operational Control

11.25. We note the high volume of strategic managerial control information received by the Executive. A further feature is the large volume of both managerial and operational information presented at Station Manager level, with the emphasis on functional presentation.

TABLE 11.4 **Descriptive Information Flow at Station Manager Level**

Subject	*Information in Report*	*Frequency*	*Control Level*
Operations	Serious incident	Ad hoc	O
	Plant state and shortfalls/emission	Daily	O
	Running plant plan and programmes	Daily	O
	Shutdown plant maintenance programme and progress	Daily	O
	National system conditions	Daily	O
	Level of critical commodities	Daily	O
	Operational performance summary	Weekly Mthly/Annlly	M
	Precipitator performance analysis	Weekly	M
	Progress against availability commitments	Monthly	M
	Environment report	Monthly	M
	Loading forecasts	Annually	O
Costs	Progress against budget expenditure levels and estimated out-turns (Station Resource Summary)	Monthly	M
	Progress against each major job	Monthly	M
	Revenue budget and future estimates (5 years)	Annually	M
Investment	Plant refurbishment programme	Annually	M
	Progress of each capital scheme, cost against budget, expected cost to completion	Monthly	M
	Future scheme evaluation and preparation	Annually	M
	Capital budget	Annually	M
Prices	By-product availability	Quarterly	O
Purchasing	Contract specification/tender appraisal	Daily	O
	Materials, spares requirements	Monthly	O
	Critical commodities	Weekly	O
Personnel	General man-management (pay & productivity, abnormal conditions payments, accidents, sickness and absence and overtime/excess hours)	Daily Weekly Monthly	O O O
	Contractors' performance	Weekly	M
	Industrial relations problems	Ad hoc	O
	Public complaints	Ad hoc	O
	NJB and NJC overtime	Weekly	O
	Progress against budget levels	Monthly	M
	Budget and future estimates	Annually	M
	Training requirements and staff appraisal	Annually	O
Working capital	Detail of major plant and spares holdings and progress against related budget	Monthly	M
	Budget and target stock levels (inc fuel)	Annually	M
	Fuel stock audit	Quarterly	M
	Coal availability report	Weekly	O
	Fuel consumption, stock and deliveries	Weekly	O

Source: The CEGB

S = Strategic.
M = Managerial Control.
O = Operational Control.

The four principal Management Information Systems

11.26. There are four main information flow systems, each of which can be regarded as coherent in itself whilst recognising that there are many cross links between all four. They are:

(*a*) Planning and Targeting;

(*b*) Technical Performance;

(*c*) Financial Monitoring;

(*d*) Budget Control.

These systems are supported in many cases by computer systems, the degree of computerisation however varies from Region to Region. A description of the main computer systems used in each Region is given in Appendix 20.

11.27. Detailed flow diagrams and descriptions of the nature and importance of the decisions taken in these areas are given in Appendix 21. These are based on the systems adopted in the NW Region but are typical of all Regions. We describe, in outline, the four principal systems below:

(a) PLANNING AND TARGETING SYSTEM

11.28. The main sub-systems are:

—September Outline Plan;

—capital budget;

—SYMAN;

—revenue budget;

—overhaul plan;

—plant readily usable and availability commitment.

The longer term planning associated with investment planning, corporate planning and system operational planning has strong vertical flows between stations and Regions, and between Regions and HQ. The short-term planning of station overhauls and transmission maintenance have the bulk of their flows contained within the location or linking with outside bodies such as contractors. However the planned maintenance programme is co-ordinated regionally and nationally through the operations planning procedure.

11.29. The detailed effectiveness of these systems has been discussed in Chapter 4 on Investment Background and Chapter 6 on Operational Planning. We concluded that operational planning was generally effective but that there were doubts about the scope of the information presented to the Executive in the investment and strategic planning field.

11.30. Much of the planning system which is subject to iterative discussions at the various levels is not appropriate to computer assistance. However, parts of the system are aided by computerisation:

(i) *The SYMAN suite;* a predictive computer simulation model of generation which can be used to examine the effects of decisions on the system. It is discussed in detail in Chapter 6.

(ii) *Capital budget;* a computer system recording existing schemes into which new proposals can be introduced and the effects examined.

(iii) *Overhaul plans;* the computer PERT program is used for resource planning and to optimise the outage duration at individual locations.

(iv) *PRU/Commitment;* the 'NELS' module of SYMAN can be used to assess the effects of overhauls, commissioning and closure programmes on margins.

(b) TECHNICAL PERFORMANCE MONITORING

11.31. The generation of heat from fossil and nuclear fuels, its conversion to electrical energy and the transmission of power require the input of many engineering skills.

— Nuclear Engineers;

— Instrument Engineers;

— Thermodynamic Engineers;

— Electrical Control Engineers;

— Design Engineers;

— Mechanical and Civil Engineers.

The running, maintenance and cost minimisation of plant operations require the flow of a great deal of detailed precise engineering information overlaid with associated cost data. The management information systems are very closely related to the operational engineering needs. A large amount of technical information especially concerned with plant reliability and design is generated at plant level. This is used locally for improving performance and for planning overhaul, but is also disseminated across plants and Regions to assist in common solutions to problems.

11.32. The main sub-systems are:

— short-term availability plan;

— actual availability;

— thermal efficiency;

— fuel use;

— merit order;

— system condition.

11.33. The information system for technical performance monitoring is the most highly developed of the four and consists largely of numerical data for which there is considerable computer assistance:

(*a*) *Short-term availability planning.* This process commences on a computer based system similar to the PRU (plant readily usable) planning but leads up to a manual system for day ahead and shorter term grid operation.

(*b*) *Historic availability reporting.* Peak availability, which does not involve significant data quantities, is handled manually but the assessment of continuous availability and the subsequent costing of outages is handled by computer, with the Plant Reliability/Availability (PRA) and the Power Station (PS) costs suite.

(*c*) *Thermal efficiency*. The monthly system for performance assessment uses the computer based STEP suite.

(*d*) *Fuel budget monitoring*. This is a manual process due to the level of analysis required in accounting for variances. The production of fuel statistics is computerised being an area of heavy data flow.

(*e*) *Merit order tables*. This system is entirely computerised. Basic tables are produced by the SYMAN suite which are updated monthly from the STEP suite to account for actual performance, and daily to account for station heat rate abnormalities.

11.34. We have discussed the effectiveness of these systems in Chapter 8 on Availability and Maintenance, Chapter 7 on Fuel Procurement and Chapter 6 on Operational Planning, when the system marginal costing merit order was commented upon. We noted a lack of co-ordination of information both at power stations and elsewhere on certain aspects of maintenance, plant design and quality assurance. With respect to merit order we noted that the SYMAN simulation program, although necessarily at a high level of complexity, was not suitable for frequent updating of the merit order which is achieved by approximate methods on a day-to-day basis. It is not clear what value could be placed on more precise data in this area.

11.35. The remaining two systems are concerned with Financial Accounts and Budgetary Control. They are very closely related, deriving much information from a common input.

(c) FINANCIAL ACCOUNTING SYSTEM

11.36. The sub-systems are:

— invoices;

— stores;

— payroll;

— financial statement;

— miscellaneous costs.

The greater part of the system is computerised and has been the subject of continued development. The main computer suites are set out below:

(i) Invoice suite:	Produces payment details, costing and reconciliation.
(ii) Stores suite:	Produces an analysis of stores and stock items.
(iii) Payroll suite:	Pays salaries and produces summary of sickness and absence, etc.
(iv) Costs and finance suite:	Collects all costs, produces statement of expenditure under budget heads and under works costs. Produces a trial balance.

11.37. This is an adequate system in most areas and, with the use of the national cost code, it can produce works costs or project costs for managerial control on request of individual managers. We have discussed the effectiveness of the system in the area of spares and stock control in Chapter 9 and concluded that the system in respect of stores control was non-optimising and that significant cost savings would result if the system were improved.

(d) THE BUDGETARY MONITORING AND CONTROL SYSTEM

11.38. There are two sub-systems:

— capital monitoring;

— revenue monitoring.

The effectiveness of this system has been discussed in detail in Chapter 3 where we concluded that the system was effective.

Level of Computing Support for MIS

11.39. The Board's computing facilities are concentrated around seven main points: Headquarters Computing Centre, Computing Planning and Development Department and the five Regional centres. Table 11.5 shows the 'September 1980 Outline Plan' estimates for computing expenditure and manpower for 1980–81 compared with 1978–79 and 1979–80.

TABLE 11.5 **Computing Expenditure in the CEGB and Manpower Employed**

	Actual 1978–79		*Actual 1979–80*		*Forecast 1980–81*	
	Exp £'000	*Man Years*	*Exp* £'000	*Man Years*	*Exp* £'000	*Man Years*
Regions	4,998	355	7,803	380	9,719	402
HQ CC	5,866	252	6,846	263	7,296	260
CP DD	934	63	1,364	67	1,763	73
Total	11,798	670	16,013	710	18,778	735

Source: The CEGB

11.40. Total expenditure of approximately £19 million is forecast for 1980–81. It is difficult to make comparisons of the level of computer expenditure with normal commercial users, because of the high level of computing use in the technological base of the industry. The computer budget of a typical commercial user would be between 1–2 per cent of turnover. On the same basis the CEGB budget is less than 0·5 per cent of turnover. We have not noticed any significant lack of computing facilities and we feel that this represents a cost effective service.

11.41. Table 11.5 shows an increase in man years in the Regions of about 13 per cent. We believe that this results from planned increase in software development and from the extra work involved as a consequence of the Regions switching from their ICL 1900 systems to the ICL 2900 systems. An additional factor is the development of digital process control systems for new power stations.

11.42. The Board's present policy is to have a large mainframe computer installed at each major computing centre connected to radial networks of distributed processors and intelligent terminals. Terminals are installed at the larger power stations and distributed processors at locations, such as Barnwood and the research laboratories. The Board has started trials for decentralised minicomputers to be located at major power stations and linked to the mainframe to provide increased power and resilience. Process control and associated data logging are dealt with by special purpose computers.

11.43. We have observed only one area where this configuration has not proved entirely appropriate. We have noted in Chapter 6 that the availability and response of the system when applied to real-time national control of loading and scheduling of plant is not satisfactory.

11.44. Appendix 22 shows the computing configuration in each of the major computing installations.

Developments Towards Centralised MIS Policy Formulation

11.45. The Board has recognised the unsatisfactory position of computing policy being the responsibility of Headquarters but with separate development and accountability for MIS in the Regions. The Headquarters computing branch have recently been reorganised under a Director-level head reporting to the Deputy Chairman. The directorate has responsibility for two existing departments: Computer Planning and Development, and Headquarters Computing Centre.

11.46. The Executive have recently questioned the need for separate development and the Regions have agreed as a policy to converge to a common set of Management Systems. To assist this process the Director of Computing has proposed setting up a Systems Development Steering Group with senior Regional officers under a Director General. The group has been set up and is working to define strategic plans for MIS development in the Board. Its terms of reference are set out in Appendix 23.

11.47. It is proposed that areas identified by the Steering Group should be assessed in detail by specific user groups to evaluate the options available. The user groups, also composed of senior Regional managers, would consider options, progress to date, future development and resource requirements and then produce firm proposals for the development of Management Systems in the specified area. The proposals would define minimum specifications acceptable to all Regions.

11.48. The following have been identified as likely subjects for study by user groups in the short term:

— power station work control;

— material and stores control;

— financial control;

— office systems;

and in the long term:

- —payroll;
- —personnel;
- —manpower;
- —fuel management;
- —system operations;
- —plant monitoring;
- —performance monitoring.

11.49. The Director of Computing has also proposed a project which has now been approved and launched to assess the role and the value of distributed computing to support power station management systems. Distributed computing requires a central large mainframe with communications to remote sites having intelligent terminals or minicomputers. Data collection and validation and some low level computing is carried out by the minicomputer on site. For higher level computing, or for aggregation at Regional level, data would be transmitted from the local computer to the mainframe at a convenient time. The output of the mainframe would be transmitted back to the local computer for printout or further computing.

Conclusions and Recommendations

11.50. Our investigation of the main management information systems leads us to conclude that in general they provide adequate information for functional management control and for operational control. Our own observations and an analysis undertaken by NW Region suggests that managers receive, in some form or other, sufficient information with adequate precision and accuracy to take appropriate functional and operational decisions.

11.51. The indications are that there is little duplication of production of information and that managers are not overburdened with information not of direct interest to their responsibility. We have not found the systems overelaborate. Indeed we have mentioned in Chapter 6 that even for the very complex simulation system there may be a case for additional precision. However, we have some comments to make on areas where we see possible benefits accruing from improved systems.

(*a*) *Strategic planning*. We have noted in Chapters 4 and 6 that the Board have adequate simulation models to assist system planning, ie for use of plant, both for operational planning in the medium term and investment planning in the longer term. We have also commented favourably on the effectiveness of the 5 year operational planning process. However we have not seen an information system which brings together information across all resources, plant, manpower, finance and other parameters such as demand and tariff levels, which would be necessary for an integrated approach to strategic and corporate planning. We believe that this lack may give rise to inconsistencies. For example, we have noted in Chapters 4 and 5 the use of targets rather than central estimates of costs and timing for investment planning without consideration of the additional resource input needed to close the gap between the target and the central estimate. The use of different cost estimates by Barnwood and the planning department is another example. A more integrated corporate planning system would encourage the investigation of a greater range of alternative strategies.[1] We are not satisfied that the Executive is given sufficient information about the consequences and sensitivities of changing resources and assumptions for all the available options.

(*b*) *Station management control.* The Station Manager is increasingly concerned with decisions which relate to the balancing of cost and benefits of performance improvements in the context of the system marginal opportunity costs. Whilst we believe that the Station Manager is well served with systems for Functional Management, Operational and Engineering Control, there is no uniform system available to serve, in a convenient form, his role as General Manager. This requires a system which makes horizontal cuts across the functional flows which already exist. This problem will become more and more acute as the average size of stations increases and their numbers decline, so that the quality of cost/benefit decisions at any one location grows in national significance. In recognition of this need the Board has established in 1975 the post of Director of Resource Planning at Regions and is now seeking to establish Resource Managers at major stations. An information system designed around the needs of general management would now be appropriate.

(*c*) *Exception reporting.* The origins of the present management information systems lie in the need for precise engineering data for operational control. This required the generation of regular descriptive reports, rather than exception reports. It appears that this tradition has been carried forward into the sphere of general and functional management control. Tables 11.2 to 11.4 show the volume of regular descriptive reports presented at Region and especially at the Executive level. The Board tells us that each main budget centre manager is expected to draw the attention of levels above him to significant abnormalities often in parallel with descriptive reports. However, we have not found that the concept of exception reporting is well developed in the Board, in particular its use for highlighting to a manager the prime areas for decision within his own sphere of control rather than for merely passing information upwards. Regularly produced exception reports are a valuable aid to preventing significant abnormalities being missed and for optimising the use of a manager's time.

11.52. The Board's management information systems have never been subject to a comprehensive review, nor have they been developed as part of an integrated strategy. We believe that, with the setting up of the new central computing directorate, the change of Regional hardware, and the possibility

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[1] The CEGB announced on 8 January 1981 that it had decided to set up a new headquarters department which will be mainly concerned with both corporate planning and strategy.

of distributed computing, it is an appropriate time to review the Board's information systems and produce a strategy for the next decade. We therefore welcome the present initiatives.

11.53. The present systems have provided adequate control in the last decade. However the increasing complexity of commercial decision making at all levels of management, the growing significance of management decisions taken at the larger stations and the strategy with respect to the nuclear programme all underline the need for this review.

11.54. We recommend that such a review should pay particular attention to the following:

(*a*) the information needed for corporate and strategic planning and the co-ordination of information resulting from horizontal integration across the functions;

(*b*) the information needed for general management especially at station level and the co-ordination of information across the functions. We would particularly like to see the continued development of the SCOPE project;

(*c*) the definition of decision oriented information needed for all levels of management;

(*d*) the use of exception reporting in management control.

We have already pointed out the lack of progress experienced after many previous studies. We therefore urge the Board not only to set up such a review but to take the necessary action to secure any potential benefits which may be identified.

CHAPTER 12

The construction of power stations

Functions of the Generation Development and Construction Division

12.1. The CEGB organises the building of its power stations through its Generation Development and Construction Division located at Barnwood near Gloucester. The Division was formed in January 1971 by the amalgamation of the three former Generation Project Groups and the Generation Design Department from Board Headquarters. The Project groups had been responsible on a geographical basis for the layout, system design, project management, contract administration and site supervision of new power station construction. The Generation Design Department had been responsible for the specification and design assessment of plant including reactors, boilers, turbo-generators and associated equipment but the CEGB has never constructed stations or designed plant. The process of evolution towards the new divisional organisation was completed in mid-1974 when the Division occupied its present headquarters at Barnwood, Gloucester.

12.2. The CEGB has told us that among the reasons for establishing the Division were:

(i) the diminishing number but greatly increased size and complexity of power station construction projects;

(ii) the achievement of economies of scale, by adopting a standardised approach and avoiding diversification and duplication of effort and design;

(iii) the opportunity to secure a major improvement in communication internally and to present a more consistent approach externally;

(iv) the need to make the best use of expertise on a flexible basis in accordance with priorities; and

(v) the opportunity presented of maximising the potential of staff in the interests both of the Board and of the career developments of individuals.

12.3. Barnwood is an integral part of the CEGB organisation and provides the vital link by which the Board's plans for developing generating capacity in accordance with forecasts for future demand are translated into reality. Some 70 per cent of the Division's effort is directly devoted to its prime responsibility of focusing and managing the client role of the Board *vis-à-vis* contractors engaged in major power station construction projects; but it also provides a technical service to power station managements who operate the plant and it maintains contact with them so as to be able to carry its responsibility for subsequent development.

12.4. We deal separately with nuclear stations in paragraphs 12.78 ff. In the case of conventional stations Barnwood places separate contracts for boilers, turbines, civil works, cabling etc and itself provides the station layout together with the systems engineering which integrates the plant and equipment supplied under the separate contracts into an operational power station.

12.5. On each contract the Division:

(i) draws up specifications incorporating user requirements and experience, issues enquiries, assesses tenders, and negotiates and places the contract;

(ii) administers the contract. This includes approving design submissions, attending to payments, variations, claims and extensions of time and ensuring that these matters and others comply with the contract conditions; and co-ordination with other contracts; and

(iii) monitors the performance of each contractor in the discharge of his contractual undertakings by acting as a design, technical, quality and financial auditor both in works and on sites; monitors contractors' progress against schedule, the productivity of their labour forces and industrial relations on site.

12.6. Barnwood's specialist services are also available to other parts of the electricity supply industry. Other divisional functions are discussed in Appendix 24 and a description of the CEGB's procedures for the control of cost on construction sites is given in Chapter 3. Barnwood employs some 2,000 people in all at a cost of about £20 million a year in salaries, travel and subsistence.

Previous Reports on Power Station Construction Problems

The National Board for Prices and Incomes

12.7. NBPI Report no 59—The Bulk Supply Tariff of the Central Electricity Generating Board, March 1968, looked at delays in the commissioning of new power stations and noted that these could have resulted in a serious shortage of supply but for the over-estimation of demand. (The subject of demand forecasting is dealt with in Chapter 4.) They estimated that the elimination of delays would have saved some £60 million in 1968–69.

The Wilson report

12.8. The Committee of Inquiry into delays in commissioning CEGB power stations, chaired by Sir Alan Wilson, reported in 1969. They concluded that the increase in plant ordered since 1959 had overwhelmed the technical, production and managerial resources of the manufacturers and that this had been exacerbated by the use of new designs. They said that the main causes of delay had been manufacturing difficulties and design faults, labour disputes and low productivity amongst contractors' workforces.

12.9. They noted with approval that new measures to assist contractors had been taken by the CEGB. They recommended more decisive management in general and a design freeze by the Board before construction started. They also recommended that the Board should use separate design and erection contracts and reduce the number of separate contractors on site. All parties should also adopt improved methods of programme management and ensure greater specialisation in this topic by staff in the field.

The first NEDO report

12.10. The report of the NEDO Working Party on Large Industrial Sites was published in May 1970. This covered all types of construction, not just power stations. It said that lump sum contracts were only suitable where clients could specify their requirements in advance with considerable precision. Otherwise there was a temptation for a contractor to exploit his right to frustration charges. It therefore endorsed the use of reimbursable contracts, restricted selective tendering and negotiation of the final contract prices and terms. It also supported a pyramidal structure of main and sub-contractors as a means of reducing the number of contractors on site directly reporting to the client.

The second NEDO report

12.11. The NEDO Working Party on Engineering Construction Performance reported in 1976. International comparisons of oil and chemical plants and power stations showed that overall foreign project times were much shorter and there were fewer delays. Construction times were shorter too and construction efficiency greater, with productivity being higher as well. Manning levels too were lower. Delays in foreign construction projects could usually be retrieved. In this country they could not. The most serious problems in the United Kingdom occurred on sites, despite the fact that in the United Kingdom control systems were in general more sophisticated than those in other countries. These findings are illustrated in Figures 12.3 and 12.4 and Tables 12.1 and 12.2 which are taken from the Report and discussed in paragraph 12.18.

The Price Commission

12.12. Report no 42 of 1979 by the Price Commission dealt with Area Electricity Boards' electricity prices. However with the Board's agreement it included a chapter on the CEGB. The report found that delays and cost increases were continuing and the reasons were the same as before. The most important among them were poor industrial relations amongst contractors' workforces on sites, low productivity and the re-design of equipment during construction. It is also clear that the contract strategy followed by the CEGB, on the basis of the advice offered by previous inquiries, had still not given sufficient incentives to contractors to finish their work on time. The Price Commission's study covered only conventional power stations. It did however report on the steps that the CEGB was taking and planning to take in order to construct future stations to time and cost and to reduce further delays on stations already under construction.

Our own investigations

12.13. In view of the extensive work carried out by previous inquiries, we have restricted our investigation of the construction of power stations to an examination of the way in which the CEGB is implementing its new policies.

We have looked in some detail at the difficulties which have been experienced with the current nuclear programme, since many previous reports have not dealt with this problem specifically. First we examine the available data and then the technical reasons for delay and cost increases. Next we deal with contract strategies and industrial relations matters. We then discuss the problems of constructing the current nuclear stations and finally discuss the role of Barnwood.

Cost increase and time overrun data

Conventional stations

12.14. All the reports noted in the previous section contained comprehensive statistics about the extra costs and delays incurred in constructing power stations. We repeat some of these here as background for the discussion and bring them up to date.

12.15. The Plowden Committee of Enquiry into the structure of the electricity supply industry in England and Wales (Cmnd 6388) also had a section on the commissioning of power stations. Table 2 on page 19 of that report gave figures for the commissioning backlog from 1963 to 1974. The steep increase in backlog from 1963 to 1969 clearly followed the increase in planned capacity. This latter followed directly on criticisms by the Select Committee on Nationalised Industries (HC 236) of supply interruptions in the winter of 1962–63 and a request from Government to the ESI (Cmnd 2177, paragraph 29) to base its forecasts of electricity demand on the 4 per cent steady growth rate of the economy put forward by the National Economic Development Council.

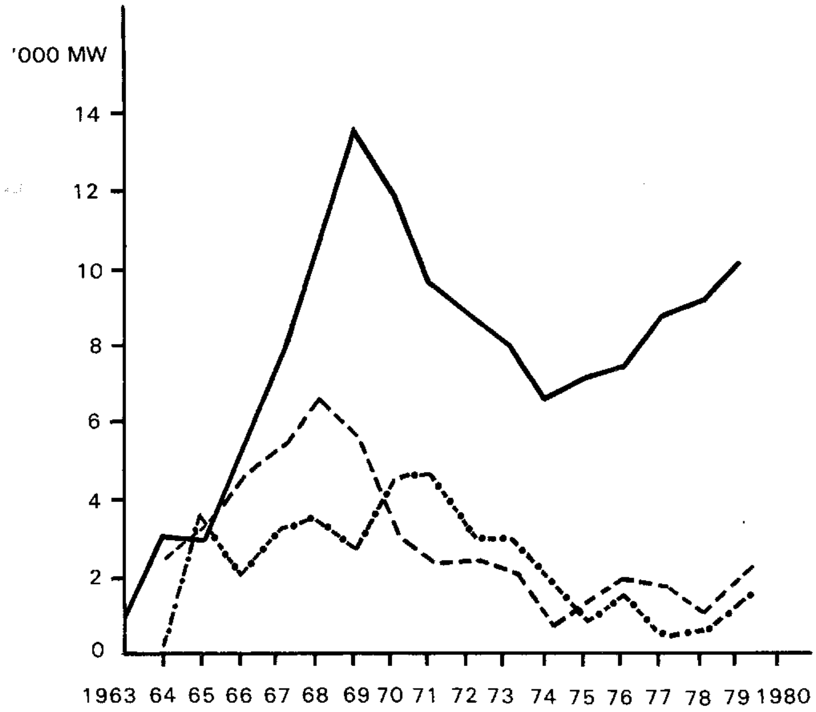
12.16. The CEGB has provided us with additional data to bring that table up to date. The data are set out graphically in Figure 12.1 which shows the amount of plant planned for commissioning during a year, the amount actually commissioned and the cumulative backlog. The peak backlog of 14,000 MW was reached in 1969. By 1974 it had been reduced by over half. Since 1974 it has risen again to 10,000 MW. However, since the amount of plant now being commissioned and indeed planned for commissioning is much less than it was when the backlog was last of the same size, in recent years the situation appears to have been getting worse in relative as well as absolute terms.

12.17. Figure 12.2 shows orders placed over the same time period for steam-driven generating plant. The peak was in 1963. In many recent years no plant has been ordered, and in the last ten years (1971–80) only 5,000 MW has been ordered. The CPRS in its report on The Future of the United Kingdom Power Plant Manufacturing Industry (1976) commented that the balancing of manufacturing capacity to achieve economic utilisation of facilities was very difficult if sudden upturns or downswings in demand occurred.

12.18. Figures 12.3 and 12.4 and Tables 12.1 and 12.2 illustrate some of the findings of the second NEDO Report. Power station construction times were much longer in the United Kingdom than abroad and man-hours used per kW of capacity were at least double those in the USA. Costs per kW were significantly higher in the United Kingdom than in the USA although

FIGURE 12.1

Power Station Construction



Key:
—— Cumulative backlog
– – – Planned for commissioning during the year
—·—·— Commissioned

Source: Plowden Report and CEGB

markedly lower than in Germany. It should be emphasised that these comparisons are based on a limited sample of conventional power stations studied in 1976.

12.19. Price Commission Report No 42 quoted examples of the magnitude of delays and cost increases for power stations. Conventional stations which had been ordered for commissioning in the last 15 years had suffered delays ranging from four months to four years on a completion time[1] of five to six years. Increases in capital costs ranged from 8 per cent[2] to 36 per cent[2] in real terms[3] and exceptionally over 50 per cent[2]. The average of these per-

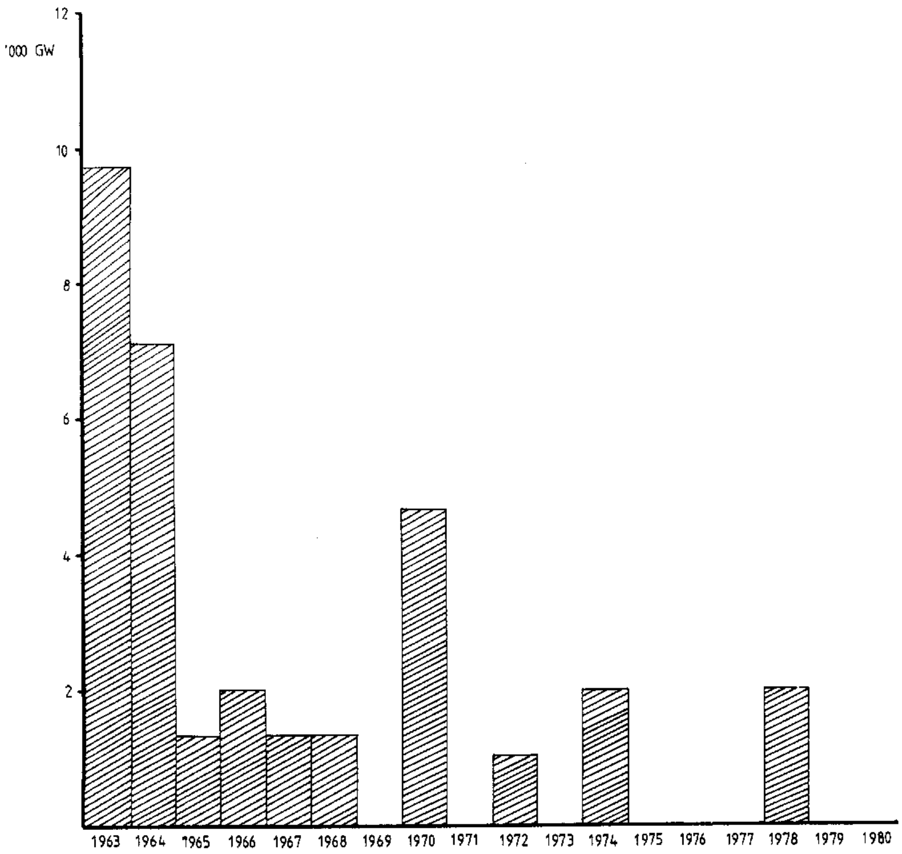
[1] To synchronisation of the first unit.

[2] These percentage increases which we have taken from the Price Commission report are not directly comparable with the 21 per cent quoted in paragraph 5.63.

[3] The definition of 'real terms' for this purpose has been discussed in paragraphs 5.63 ff.

FIGURE 12.2

Orders Placed for Turbo-Generators by the CEGB



The 6 pump-turbines (1800 MW nominal) ordered for Dinorwic pumped stage scheme in 1975 have been excluded since they are not conventional turbo-generators.

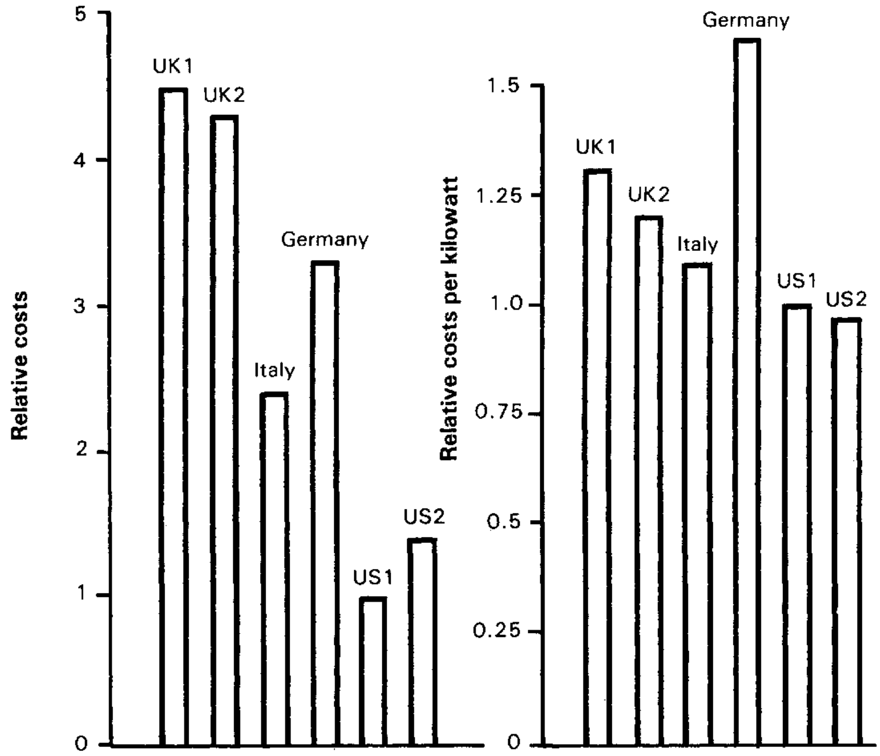
Source: CEGB

centage increases was 19. All stations which had already been commissioned had cost £250 million more than planned and those still be be commissioned had cost £500 million more to date at 1979 prices.

12.20 The CEGB has told us that these figures are still broadly correct. However, it is now the Board's policy to include a risk margin in capital estimates which is intended to cover inevitable additions to real cost which cannot be specified meaningfully in advance. If this practice had been followed earlier the £250 million figure quoted above would have been under £100 million and the £500 million under £400 million.

FIGURE 12.3

Power stations: Relative costs and relative cost per kilowatt (US1 = 1)



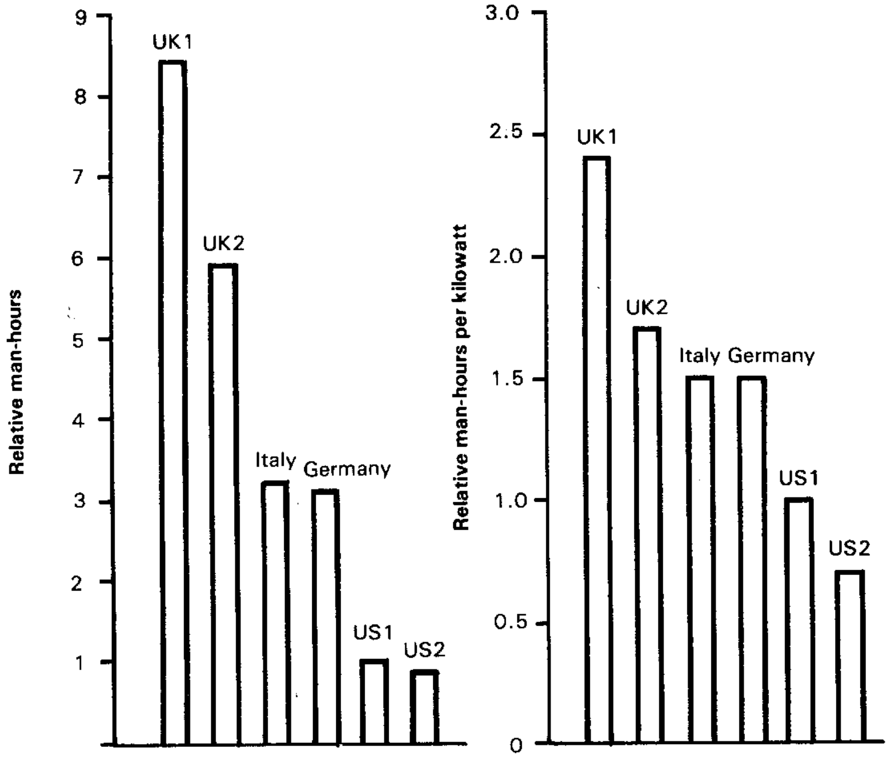
Source: NEDO Report on Engineering Construction Performance (1976)

12.21. It was also reported that the CEGB had told the Price Commission that the consequential cost to the consumer of delays caused by late commissioning of the more efficient plant was in the range of £100 million to £200 million in the year 1979–80. This was approximately 3 per cent to 5 per cent of the CEGB's total costs. The CEGB has told us that the same figures are broadly correct for the year 1980–81.

12.22. The cost make up of constructing a typical conventional power station of 2,000 MW together with Barnwood's engineering man years are shown in Figure 12.5. Appendix 25 lists all stations currently under construction and their present forecast costs and completion times compared with the original forecasts. The five conventional stations currently under construction are expected to be delayed on average by 2·3 years and the forecast cost increases average 19 per cent in real terms.

FIGURE 12.4

Power stations: Relative man-hours and relative man-hours per kilowatt (US1 = 1)



Source: NEDO Report on Engineering Construction Performance (1976)

Nuclear stations

12.23. The Board has three AGR stations currently under construction. Site work has begun on a fourth and design of a PWR has started. Average forecast delays for the first three are currently 8½ years on an average planned overall construction time of 6½ years. The average cost overrun to date in real terms is just over 100 per cent. By contrast the US company Westinghouse has undertaken the construction of 12 pressurised water reactors (PWRs) since 1971. The average actual and projected delays are 3¼ years on an average planned 5¾ year construction period.

(Source: *Nuclear Energy,* 1979, vol 18, December, no 6.)

12.24. Of the approximate cost increase of 100 per cent quoted above about 33 per cent has been due to design or policy changes including developments

TABLE 12.1 **NEDO case studies: measures of project and construction performance**

Projects	*Over run on planned project time %*	*Actual project time months*	*Actual construction time months*	*Average construction productivity index*	*Pipework productivity index*	*Peak no of men on site*
	Note 1	Note 1	Note 2	Notes 3 & 5	Notes 4 & 5	Note 6
Power stations						
UK 1	64	87	69	29	na	2200*
UK 2	18	73	59	40	31	2050*
Italy	9	50	34	45	na	1300*
Germany	8	41	34	45	na	1700*
US 1	0	50	34	67	100	700*
US 2	19	32	31	100	87	720*

Source: NEDO Report on Engineering Construction Performance (1976)

na = not available

Notes

1. For purposes of comparison, project time on power stations is measured to synchronisation of the first unit.
2. Construction time is measured from start of civil engineering to completion of construction
3. Average construction productivity is the ratio of estimated work content to total man-hours. Work content is based on length of piping for oil and chemical plant and on number of kilowatts for power stations; these give only a very approximate measure of work content.
4. Pipework productivity is the ratio of piping length (in some cases weight) to the man-hours spent on pipework.
5. The index is obtained by setting to highest productivity ratio in each case study to 100. Comparison is valid only between projects within each case study, not between case studies.
6. Figures marked * refer to total numbers on site, not just those on the unit studied. In these cases they do not provide a measure of performance but they do indicate the overall scale of the site.

TABLE 12.2 **Power stations: planned and actual time for placing main contracts to synchronisation of the first unit, months**

	UK 1	*UK 2*	*Italy*	*Germany*	*US 1*	*US 2*
Planned time	53	62	46	38	50	27
Actual time	87	73	50	41	50	32
Over run	34	11	4	3	0	5
Over run, %	64	18	9	8	0	19

Source: NEDO Report on Engineering Construction Performance (1976)

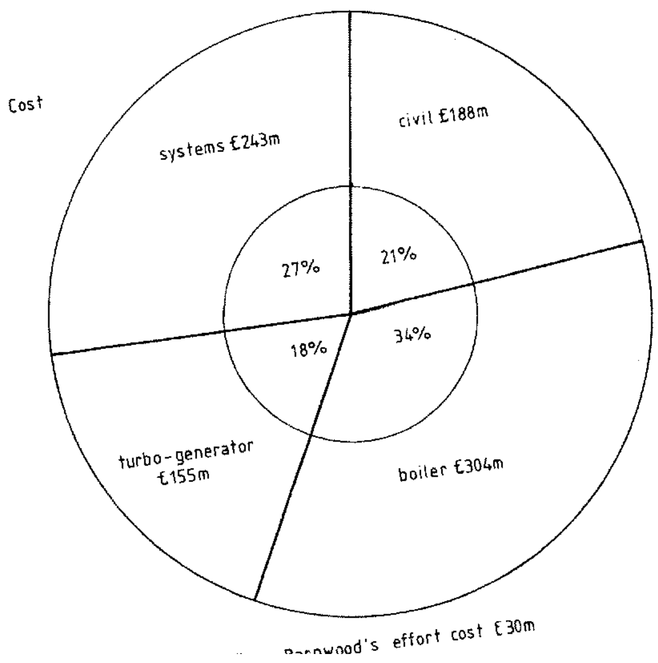
in legislative requirements, 25 per cent to under-estimation of the cost of particular parts of the works and of changed commercial arrangements and 42 per cent to delays. However, because not all delay costs can be related to the same base accounting date, the figure of 42 per cent may be an over-estimate. The delays themselves were mainly caused by design changes or the provision of additional hardware to meet new safety requirements or to overcome technological problems, poor original design or errors of workmanship. Low productivity also had its effect. Industrial relations problems have brought delays which in some cases have been as long as those for conventional power stations.

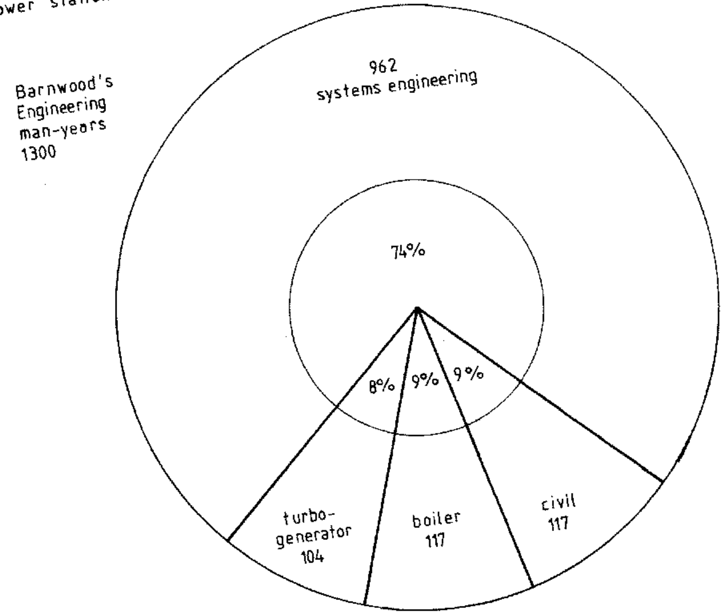
12.25. Whilst it is possible to classify reasons and to compute averages as we have done above, it should be noted that the technical and commercial problems encountered at individual stations differ widely from one another.

Figure 12.5

Cost and Engineering Man Years

Typical 2000MW coal-fired power station (repeat design)





EXPERIENCE OF THE SOUTH OF SCOTLAND ELECTRICITY BOARD (SSEB)

12.26. The other major authority in Great Britain which constructs large nuclear and conventional power stations is the SSEB. This Board has kindly made available data to enable us to compare its construction performance for three recent large stations with that for stations of similar size belonging to the CEGB.The construction times for the SSEB's three stations have ranged from $5\frac{3}{4}$ to $6\frac{1}{4}$ years against a planned time of 5 years to synchronisation of the first unit.

12.27. Having looked at the data, we believe that differences of location, plant specifications and employment conditions make it difficult to draw valid deductions from a comparison with construction times in England and Wales. The SSEB agrees. However, we have noted a different emphasis in one aspect of industrial relations practice.

12.28. The majority of contractors in Scotland belong to the Scottish Engineering Employers Association (SEEA) which, as well as representing its members who employ engineers in factories, also administers the Engineering Employers Scottish Sites Group which represents EEF[1] contractors on construction sites in Scotland. The group has a representative on power station construction sites whose job is to monitor the approach of the contractors to industrial relations. The representative and the contractors meet formally at regular intervals under the chairmanship of the Secretary of the SEEA to review the overall industrial relations situation on site. As we note in paragraphs 12.69 ff, it has not yet been possible to negotiate a comprehensive national site agreement in England, but the CEGB has taken steps over the past year to improve co-ordination of industrial relations at Grain and Drax.

Technical Preparation for Contracts

12.29. The previous reports quoted above have drawn attention to many technical failings in preparing and executing construction projects. Where the criticisms have been made of the CEGB, it has freely admitted them. It should be borne in mind that delays now being experienced are in many cases the result of decisions taken 15 years ago. In particular the CEGB has stated that the improvement in plant efficiency and capital cost per kW brought about by the introduction of 500 MW units in the 1960s was bought at a price. At the time these sets were ordered neither the Board nor its suppliers made adequate allowance for the fact that, if reliable plant was to be provided within reasonable project timescales in order to meet the forecast increase in demand for which the CEGB had been requested to provide capacity (paragraph 12.15), then the new large plant which alone could meet that demand would have had to be developed and tested in far greater depth before contractual commitment to the provision of hardware. This experience has led the Board to adopt a policy of replication of proven designs for new turbo-generator units and boilers, and of general component standardisation wherever possible. Feed pumps and transformers are good examples of standardisation.

[1] Engineering Employers' Federation.

12.30. This policy of replication has been implemented in the contracts for the completion of Drax power station and for the construction of Heysham II. The designs will replicate those used at Hinkley Point B except in so far as safety or operational experience dictate changes. Similarly preliminary design work for the proposed PWR at Sizewell is proceeding on the basis that two of the now standard 660 MW generators will be used instead of a single one of twice that capacity capable of converting the whole output of the nuclear reactor into electric power. The CEGB is thus following its adopted principle of introducing new designs for major plant items no more than one at a time. Furthermore, the turbines will have elements common to those already in use.

12.31. Replication has its limitations, however. There has been a ten year gap between orders being placed for the original and replicated designs of turbines and boilers at Drax. It is the CEGB's view that, for replication to achieve the greatest benefits, two years should be the greatest gap between orders. Moreover, economies are possible from placing regular orders to the same design. However, replication also implies purchasing the plant by single tender action, and it is difficult to quantify what extra cost this might bring, thereby offsetting some of the advantages.

12.32. In order to overcome the delays caused by design changes during construction, the CEGB's policy is now to have all substantial design work completed by contractors before manufacture of hardware begins, except perhaps for what are thought to be minor details and long-lead items. This policy has been implemented for the advanced gas cooled reactor (AGR) at Heysham II for which a separate design contract has been let, rather than as often in the past, a combined design and build contract. We were told by the CEGB that although separate design contracts are now general among the larger electricity utilities in the world British manufacturers have been reluctant to take on such contracts without a guarantee of obtaining the subsequent hardware contract. It is also intended that, once complete, a design should not be altered except for very serious reasons.

Contractual Relationships

12.33. Previous reports have noted that it is essential to have a relationship between client and contractor which is fair to both parties and motivates them both to finish the construction on time and within the planned cost. Even ignoring inflation, this is difficult enough to effect on any large construction site where there have been in the past on occasion over 100 separate contractors employing in total up to 2,500 men, working for upwards of six years. Most forms of contract have been tried by the CEGB at some time. For example following the recommendations of the Wilson and NEDO reports noted above the Board let five reimbursable erection contracts for Grain power station separately from the 122 contracts for supplying hardware. There were only the five main contractors on site.

12.34. However, the results of this policy were thought to be unsatisfactory (see paragraph 12.49) and the CEGB now aims to have 10 to 15 main contractors on site, the number being determined by the logical structure of sub-contracts, the number of men which each contractor can easily manage and the mix of skills required. This is still a significant reduction from the figure of 100. This policy is not applicable to nuclear stations because of particular constraints, as will be seen in paragraphs 12.93 following, 12.102 and 12.103.

12.35. It is also now the CEGB's policy generally to avoid the use of reimbursable contracts and to place lump-sum contracts coupled with incentives and a 'key-date' procedure. The 'lump-sum' is subject to adjustment for inflation during the construction period. The essence of the key-date procedure is that at the beginning of a contract, targets are set for the amount of work to be completed in each six-month period. If any part of the work is not finished by the agreed time, the contract payment due at that date can be withheld until the delayed part is complete. Work done in advance of schedule will not be paid for until the key scheduled date. Such a procedure has been agreed for the Drax completion main contracts, but the National Nuclear Corporation (NNC) has told us that for Sizewell B nuclear station and Heysham II it would agree to key-dates being set for a main contract only for one year ahead at a time. This is perhaps an indication of some of the perceived uncertainties in nuclear construction.

12.36. The main civil engineering contract for the Dinorwic pumped storage power station, which had been placed with a consortium, has been changed from reimbursable target cost with work measurement to reimbursable with key-date incentives. This altered contract strategy has yielded substantial cost savings, and has accelerated the construction programme. Site overheads associated with contract cost accounting have been reduced and the incentive system makes it more likely that the remainder of the contract will be completed on time.

Management of Construction on Site

12.37. The CEGB believes that one of the major reasons for the lack of success of its contract strategies has been the reluctance of contractors to accept their full measure of joint responsibility for completing power stations to time and cost in a climate of low ordering, high inflation, and reimbursability of site labour costs. Contractors' work forces have also been inclined to prolong the work in hand both in the factory and on site. The Board has therefore initiated at Drax completion and Heysham II a 'management group', chaired by Barnwood, as a means of overcoming this problem through the promotion of cohesion and discipline between all parties in the interests of the project as a whole. Acceptance of this concept and its obligations is being made contractually binding before contractors start on site and compliance with decisions agreed by the group is not a ground for a claim against the CEGB for extra costs. The role of these groups is mainly in the context of industrial relations and so will be discussed in paragraphs 12.61 ff. However, the NNC has told us that it would have preferred the group for Heysham II to be chaired independently.

12.38. In many cases Barnwood has also had to provide extra-contractual assistance on sites to safeguard its projects. Changed responsibilities of client and contractor have been written into contracts. The Board says this has been done in such a way as to allow the transfer of responsibility back to contractors when this becomes justified by their performance. All existing contracts for nuclear stations have been amended in this way.

12.39. Originally a comprehensive contract for each AGR station was placed with a consortium. Project management, including site management was largely in the hands of the consortium and not in the hands of the CEGB. These contracts have now all been changed. The changes are discussed in paragraphs 12.97 ff.

12.40. The greater involvement of Barnwood staff in site management has naturally not found favour with all contractors. Some have said to us that the current involvement by Barnwood falls between two extremes. It should either intervene much more or much less. This question is discussed in the next section. We note, however, that the CEGB's policy of taking greater involvement on sites came about as a result of failure by contractors to overcome serious delays.

Industrial Relations

12.41. The Wilson Committee (1969) concluded that low labour productivity and (on some sites) labour disputes, were among the main causes of delays in power station construction and subsequent studies have confirmed these findings. The NEDO report on Large Industrial Sites (1970) concluded that industrial relations institutions and practices were no longer relevant or effective as regards large construction sites and the 1976 NEDO report on Engineering Construction Performance identified site morale and labour relations as the main problems needing attention. The Price Commission, reporting on Area Electricity Boards in 1979, found 'ample scope for achieving improvements in industrial relations and productivity in power station construction' and noted that efforts were being made to establish more appropriate institutions and procedures. The subject has recently also received attention from the Select Committee on Energy.

12.42. To understand the current situation it is necessary briefly to describe the structure of collective bargaining in the industry and to recall the diagnoses and prescriptions of earlier inquiries. The main categories of site work involved in power station construction are civil engineering, mechanical erection (including thermal insulation) and electrical installation. Each of these activities is undertaken by one or more contractors and their workers are covered by separate national agreements on basic pay and other main conditions of employment. These include some twelve different national agreements which can apply on large construction sites, negotiated by eleven independent employers' associations with eleven different trade unions. The main employers' organisations involved are the Oil and Chemical Plant Constructors' Association; the Engineering Employers' Federation; the Electrical Contractors' Association; the Heating & Ventilating Contractors' Association; the Federation of Civil Engineering Contractors; the National Federation of Building Trades Employers; and the Thermal Insulation Contractors' Association. The main employees' organisations are the Transport & General

Workers Union; the General and Municipal Workers Union; the Amalgamated Union of Engineering Workers; the Electrical, Electronic Telecommunications & Plumbing Union; the National Union of Sheet Metal Workers, Coppersmiths, Heating & Domestic Engineers; the Amalgamated Society of Boilermakers, Shipwrights, Blacksmiths and Structural Workers; and the Union of Construction, Allied Trades and Technicians.

12.43. National agreements are supplemented at local level by agreements between individual contractors, local union officials and shop stewards, particularly with regard to bonus payments which have commonly ranged from 50 per cent to 100 per cent and exceptionally up to 400 per cent of basic pay. The CEGB has told us that this wide range is an indirect effect of Government incomes policies over the last decade. The resulting employee dissatisfaction over the numerous anomalies that occur between groups of work people working side by side on the same site and engaged in broadly similar work is a continual restraint upon the development of improved industrial relations. Large construction sites have been characterised by poor morale, high absenteeism, very low productivity and (with the possible exception of the civil engineering work) numerous disputes and stoppages over bonus rates.

12.44. Prescriptions for improvement proffered by the various inquiries over the past decade have all followed the same general lines, including:

(i) stronger project management by clients, with higher status and management skills to complement engineering expertise;

(ii) client to ensure contractors have adequate IR skills;

(iii) client to co-ordinate contractors as a team operating to common IR policies;

(iv) introduction of work study and measured bonus schemes;

(v) client to monitor performance and bonus schemes in detail;

(vi) national and district TU officials to be involved, jointly with contractors and client, in planning and monitoring construction projects;

(vii) a co-ordinated national agreement for all large sites, increasing the proportion of base rate to bonus;

(viii) co-ordinated site agreements within the national framework;

(ix) improved disciplinary procedures.

Initiatives by the CEGB

12.45. Responsibility for relations with his employees necessarily rests with the contractor. However, the CEGB has felt obliged to assume an increasingly interventionist client role on the industrial relations aspects of power station construction in recent years. Barnwood now provides continuous top level monitoring and involvement in the industrial relations problems of the construction sites. Overall responsibility for this rests with one of the two Directors of Projects, assisted by a specialist industrial relations advisory service. At site level the equivalent responsibility lies with the CEGB Site Manager, who is in constant touch with Barnwood. The Site Manager, is assisted by a Project Industrial Relations Officer whose role is to keep a CEGB finger on the pulse of site industrial relations, generally facilitate communications with contractors and with Barnwood and provide specialist support to the Site Manager. The Project Manager meets regularly (normally at least once a week) with the Site Manager and Industrial Relations Officer to review the local situation, discuss any cases coming up at Industrial Tribunals, etc. Any points having wider implications are circulated to other sites through the central Industrial Relations Branch.

12.46. Barnwood's objective is to be an informed buyer and motivating client and not to undertake the job it is paying contractors to perform. The Division sees its monitoring role as an essential means of remaining an informed buyer and of identifying areas in which support needs to be given to individual contractors to secure an improved site performance. The contractors have traditionally looked to their associations for information and advice. However, as each association oversees only one sector of a project's operation, additional advice and guidance are essential to ensure that the overall needs of the project are recognised. Therefore Barnwood has sought to meet the needs of contractors, for example with assistance in assessing the impact of Health & Safety and Employment legislation, handling tribunal cases, etc and generally in helping them to rationalise and understand the trends in industrial relations and in the labour market. In 1978 Barnwood commissioned an investigation by the Tavistock Institute of Human Relations into the human and organisation factors affecting power station construction. The Institute's report in 1979 confirmed the findings of earlier studies (see paragraph 12.41) and proposed a further programme of action research, including overseas comparisons.

12.47. Barnwood has shown, particularly over the past year, that it is prepared when necessary to be more positively interventionist. For example, in the case of reimbursable contracts, productivity is now closely monitored and if Barnwood is not satisfied with a contractor's performance it will apply work measurement techniques and if necessary undertake activity sampling to bring him up to the mark. In one case—Ince 'B'—it has intervened to rephase construction. In another—Grain—it has insisted on a common level of maximum bonus payments. And in a third—Drax completion—it has obliged contractors to co-operate in a joint project management body. All of these cases are discussed more fully below. Barnwood has also intervened on occasion to secure a change in a contractor's site management personnel. Knowledge that Barnwood will intervene in these ways is said to be gradually forcing contractors to adopt a more sophisicated approach to site management.

12.48. Most of the problems on site arise during the mechanical construction phase and during the terminal phases of a project. The civil engineering work, which is mainly concentrated at the outset of a project, produces significantly fewer industrial relations problems. This stems from two main differences compared with the mechanical work: first the civil engineering contractors and workers have a common enemy, the weather, which helps to unite them as a team; secondly, and more importantly, all the profits in the civil engineering work are made on site so their best management is concentrated there, bringing a higher degree of professionalism and much lower supervisory ratios (1:7) than on the mechanical work (1:20). The profit locus of the mechanical contractors, by contrast, is in the factory and their best management is concentrated there rather than on site. Indeed, unlike the civil side, there is on the mechanical side no recognised distinction between project and site engineers.

12.49. As a means of reducing the scale of the problems in mechanical construction the CEGB attempted to reduce the numbers of separate contractors involved in a project. There is no single company in the United Kingdom competent to undertake the whole project so there must necessarily be more than one main contractor. In practice Barnwood has found that there is no viable alternative to the engagement of one or more different specialist contractors for the civil, mechanical and electrical work respectively, and within those broad specialisms a number of more narrowly specialised activities must be sub-contracted. From the industrial relations standpoint Barnwood has found from experience that if the number of men employed by any one contractor rises much above 400, the man-management task becomes too great. It therefore sees no viable alternative to the multi-contractor arrangement, with a contract strategy which fosters a cohesive approach to the work by all contractors.

12.50. We have noted above that one means suggested by earlier inquiries for increasing client control over contractors was the reimbursable contract. The CEGB introduced this form of contract in a number of projects during the 1970s, but with highly unsatisfactory consequences for site industrial relations. With the client seen as paying the labour bill relationships of contractors with their employees became confused. Self-discipline of contractors in matters of efficiency tended to be undermined and the trade unions continually pressed for improved bonus payments in the belief that the client would foot the bill. As we have said, the Board now prefers to adopt lump-sum contracts for site erection whenever possible.

12.51. The industrial relations problems of individual CEGB construction sites must be viewed in the context of continuing projects on other, often closely located, CEGB sites, the more general industrial relations problems of areas like Merseyside and the Thames estuary where some of the Board's major projects are located, and the short-term policies of some other clients (eg some petro-chemical companies, Thames Barrage) who because they have no longer term continuing commitments like the CEGB have been able to pay large bonuses for 'completion' on their 'one-off' projects. Against this difficult background the CEGB has over the past year displayed a new and welcome firmness. This is well illustrated by its recent handling of industrial relations problems at Ince 'B', Littlebrook 'D' and Grain.

Ince 'B'

12.52. In 1979 there was a serious and continuing decline in labour productivity on the Ince 'B' project. Despite several direct warnings to local and national trade union leaders by Barnwood and contractors, productivity failed to improve and it became evident that the first unit (No 5) could not be commissioned as planned, in time for the peak winter demand of 1979–80. Barnwood decided to re-programme the project by delaying completion of Units 5 and 6 by one and two years respectively. Labour requirements were thereby cut at Barnwood's insistence despite the contractors' reluctance and some 700 contractors' employees were declared redundant in December 1979. The new programme required commissioning of Unit 5 by October 1980 and union representatives were advised that failure to achieve this date would jeopardise continuing with Unit 6 to completion. There have since been substantial improvements in productivity and Unit 5 was synchronised with the national grid on 10 August 1980, two months ahead of the revised programme.

Littlebrook 'D'

12.53. Unacceptably low levels of labour productivity on turbine erection at Littlebrook 'D' have delayed the whole project by 84 weeks. Barnwood has persuaded the contractor to renegotiate his work procedures with a view to introducing some 31 measures to improve productivity including:

- —greater flexibility in using the rigging workforce;
- —greater flexibility between direct and indirect work (with reference to minor modification work);
- —pipefitters to undertake simple rigging;
- —all members to be allowed to remove and replace very small steelwork for work access purposes.

Grain

12.54. Work at Grain commenced in June 1971 and was beset throughout the 1970s by disputes and stoppages. Not all the loss was due to internal action (eg there was a national civil engineering strike in 1972), but the main subject of disputes was bonus rates and other site payment disparities. In addition, from time to time the operatives had banned overtime. The CEGB closed the site for an extended period in 1976 following a dispute over the provision of overalls and increased bonus payments for the boiler erection workforce. The scope of the boiler contract was reduced and the number of main contractors was increased from five to eight, thereby reducing and making more manageable the number of employees of each contractor.

12.55. In June 1979 the Mechanical Construction Engineering Agreement provided that the parties would not amend the payment regimes of existing bonus schemes during currency of the Agreement. This covered 1,274 of the 1,737 workers at Grain. Broadly similar arrangements were introduced in respect of all other trades (excluding laggers) to give maximum earnings of £4.60 per hour. However, the laggers at Grain had already secured bonus payments of £4–£5 per hour from their employer (CDN Insulation Ltd) in 1977, with peaks of £8–£9 per hour. The contractor claimed high rates of productivity were being achieved but the CEGB alleges that its investigations in 1978 had revealed inaccurate recording of 'lost time'. The CEGB insisted the contractor manage his work properly but he was unable to secure workforce agreement to any change and finally in July 1979 he was obliged to give notice to the GMWU of termination of the bonus scheme.

12.56. By August 1979 the project was already some four years behind schedule and the man-hours required to perform tasks similar to those carried out in the 1960s (eg at Fawley) had increased by more than 30 per cent. Over 2 million man-hours had been lost directly by industrial action and a much greater number had been lost indirectly through picketing, etc. There then followed a series of events which placed completion of the project in jeopardy. The laggers were laid off in August 1979 at the time of a mechanical scaffolding strike on the site, and when by December 1979 CDN had failed to secure the laggers' agreement for a return to work on terms acceptable to the CEGB, the Board terminated CDN's contract. Other contractors declined to tender for the work and efforts by the main contractors to undertake the work with GMWU labour were frustrated locally. By February 1980 Cape Contracts Ltd had reached agreement with the GMWU at national level on the terms for recruitment of laggers but the union's local Branch rejected them. Other unions indicated their willingness to take on the lagging work. Mediation by the TUC was attempted in March/April but their proposal for resolving the deadlock was unacceptable to the CEGB and to the other craft unions. Unit 2 was completed in April 1980 but on 21 April the Board suspended all work on Units 4 and 5, some 600 mechanical and electrical employees were made redundant and the unions were advised that work in Units 1 and 3 would cease at the end of June.

12.57. Following the CEGB's April announcement, during May the other unions encouraged the recruitment of up to 60 of their members for training to undertake the lagging work at Grain. Work has since proceeded on Units 1 and 3. In October 1980 an outline agreement was reached under TUC auspices between the three main unions involved (GMWU, AUEW and EETPU) for a smooth transfer of lagging work from replacement laggers to GMWU laggers, who would complete the work on Unit 3 and any further units that might be re-entered into the programme. The manner in which Unit 1 lagging would be handled was to be the subject of further discussions between the parties. They also agreed that the bonus limits set by the CEGB would be observed by all the unions.

12.58. In August 1980, the CEGB reached agreement with the contractors at Grain on the proposed terms of a new 'Site Understanding' for imposing labour discipline and earnings control. This has now been accepted by the electrical and mechanical unions and is under active consideration by the Thermal Insulation Contractors' Association and civil engineering unions. The understanding, which will form an integral part of each contractor's contract, provides for a commitment to completion of Units 1 and 3 respectively by 31 May and 31 December 1981; a common £4.59 per hour limit on total earnings for all groups of employees; incentive payments to be based on a self-financing productivity scheme linked to the completion dates; that the client may suspend work on Units 1 and 3 if completion is jeopardised by industrial disputes; and that a Joint Disputes Panel comprising representatives of all contractors and unions be established for speedy resolution at site level of all disputes arising on the project.

12.59. The proposal for a Joint Disputes Panel (JDP) is particularly significant. It provides for one national official of each union and one member of the off-site management of each contractor to be full members of the JDP. Additionally, representatives of the employers' associations will act as advisory members, and national representatives of the particular employers and unions involved in a dispute will be invited to attend, also in an advisory capacity. The JDP will serve as the national stage of the disputes procedure in relation to any questions arising at Grain which are pursued beyond the first external stage of the existing procedure. It will meet within ten working days of a request from the company or unions involved. It is intended that the understanding will include laggers as well as all other site employees, and that its disciplinary procedures will supersede those of the TICA and other National Agreements.

12.60. A further important provision concerns the maintenance of productivity levels acceptable to the CEGB. It is provided that the Board will 'constantly monitor progress' by use of its Productivity Audit Group supplemented as necessary by the Site Manager and Project Accountant, and through weekly meetings of the Board's Site Manager with the contractors' site management. If it becomes apparent that one or more contractors are not achieving the payment/productivity ratio or the rate of production needed to meet the agreed completion dates, the Board's Site Manager will notify his Project Manager, with copies to the contractor's Site Manager and off-site Director, and a meeting of the JDP may be convened by the CEGB.

Management groups

12.61. As we have noted earlier it is now the Board's policy, in placing all future contracts, to insist that all significant tenderers will confirm their willingness, as a contractual commitment, to participate in a Management Group and to abide by policies determined by it, particularly as regards the harmonisation of incentive bonus schemes and site discipline procedures. The Board is also giving more emphasis in its selection of contractors to their competence in handling industrial relations problems and is supporting those engaged in establishing work study data as an objective basis for bonus schemes and in monitoring and regular auditing of payments levels and productivity on site.

12.62. A Management Group, comprising representatives of some 12 main contractors and three major employers' associations, is currently in operation at Drax. The Group, which meets monthly, is chaired by the CEGB Project Manager, and a Barnwood Director of Projects and the Project Industrial Relations Officer also attend. The Chairman's role is to assist the Group to reach agreement on problems of common interest and to implement that agreement. Barnwood also acts as a resource to the Group, providing information, guidance (eg on contractual obligations) and advice and, at the Group's request, undertaking payroll audits and monitoring productivity.

12.63. The Group is essentially an exercise in contractor self-discipline. Very close attention is being paid to the harmonisation of industrial relations policies and practices, particularly as regards incentive bonus payments and other payments practices (eg severance payments). It is agreed Group policy 'to monitor the industrial relations policies of even the smallest sub-contractor as experience on other sites has shown that the problems of small sub-contractors could cause problems for the whole site, unless controlled'. The results of Barnwood work study audits of individual contractors are reported to the Group. They also regularly consider data on progress relative to plan, days lost by industrial disputes, and changes in external factors (eg National Agreements) affecting the project.

Joint Study Groups

12.64. Another innovation at Drax is the Joint Study Group. This Group meets quarterly, also under the chairmanship of the Project Manager and with a similar array of Barnwood personnel in attendance as for the Management Group. The Barnwood representatives are full members of the JSG, however, for it is a tripartite body comprising representatives of CEGB, the trade unions and the contractors and their trade associations. The unions are represented by national officers and the contractors by their off-site directors and officials of the employers' federations. The JSG reviews progress, monitors such matters of common interest as contractual arrangements, work scheduling, work flow and access, productivity, shift working, bonus levels, disputes, health, safety and welfare, labour supply and general industrial relations questions and endeavours to identify developing problems and advise upon early corrective action.

Recent trends in days lost and productivity

12.65. Table 12.3 shows the time lost by industrial disputes on power station construction sites. The reduction in 1979 was against the national trend and there was a further reduction during the first half of 1980. Time lost through industrial disputes in 1979–80 is running at a level below the average recorded over the past decade. The number of stoppages has remained high, but they were of shorter duration than in the past, averaging a little over 40 hours per man in 1979–80 compared with an average of over 90 hours per man in the previous two years.

TABLE 12.3 **Contractors' Labour Disputes on the CEGB's Sites**

Year	*Number of strikes*	*Man hours lost (millions)*	*Hours lost per man*	*% time lost*
1976	221	1·57	154	7·7
1977	287	0·66	59	2·9
1978	311	1·3	115	5·8
1979	298	0·75	68	3·3
1979 (Jan–Sept)	210	0·64	57	3·8
1980 (Jan–Sept)	239	0·26	26	1·7
Annual averages				
1971–1979	229	0·83	80	4·0

Source: The CEGB.

12.66. The CEGB has told us that absenteeism remains around 10 per cent or more although considerable variations occur between contractors and different projects. It has not been able to supply specific comparative information since contractors adopt different conventions in calculating absentee percentages. However, there appears to the CEGB to be some improvement in recent months, reflecting the growing levels of unemployment and redundancies in the country generally.

12.67. A recent improvement in productivity at Ince 'B' was discussed in paragraph 12.52: one example of this improvement was an increase in the cabling rate from 2·5 to 6·8 cables fixed per man-month, representing a 172 per cent improvement in productivity and a 50 per cent reduction in labour costs. Potentially significant moves have also taken place at Grain, where more effective supervision has increased the average length of time actually spent at the workface from 2·5 hours per shift to about 6 hours per shift. Output has consequently doubled despite the limitation on maximum earnings.

Shift working

12.68. The CEGB is also currently insisting on double day shift working where appropriate on new sites. A double day shift arrangement would largely eliminate the need for overtime and would create more employment opportunities in the short term. The first opportunity for implementing the policy is at Drax, where the contractors are shortly to present their plans for double day shifts to the CEGB.

A national agreement for large construction sites

12.69. The ESI and all other parties involved in large construction sites have for some years been striving to achieve a national agreement which would establish a consistent industrial relations framework, with controls on wages and conditions of service for the workforces of all mechanical contractors. The idea of a National Joint Council and a comprehensive national agreement for the industry, with local Site or Project Councils and Site Agreements within the national framework was recommended in the 1970 NEDO Report on Large Industrial Sites. The idea won general support in the industry but progress has been very slow.

12.70. The 1970 NEDO Report also recommended the formation of a clients' council to assist communications and co-ordination between clients. The CEGB took a leading role in establishing such a council, which meets regularly at national and regional levels, and has played an active part in encouraging and assisting progress towards a national mechanical agreement for large construction sites. A joint management/union working party was established, representing the unions and employers in the mechanical engineering construction industry, but prolonged discussions over several years were unsuccessful in bringing agreement. Early in 1979 the industry's two main employers' organisations, the Engineering Employers Federation and the Oil and Chemical Plant Contractors Association, and the trade unions representing employees decided that more rapid progress might be achieved with the assistance of an independent chairman. Their joint working party first met under the independent chairman in February 1979. Its report, agreed in October the same year, presented detailed proposals for the constitution of a National Joint Council; a model constitution for a Site Joint Council; National Working Rules; and the main elements of a Site Agreement.

12.71. Broad agreement in principle on the content of the proposed national agreement was secured at national level on the employers' side by early in 1980. There then followed a lengthy process of consultation with the regional associations of the EEF, and in July 1980, after consulting the construction industry's main clients, the employers' side finally submitted the draft agreement for consideration by the trade unions. Negotiations are in process but whether they can be brought to an early successful conclusion is uncertain.

12.72. The main features of the proposed agreement include a National Joint Council comprising an equal number of employers' and employees' representatives meeting under an independent chairman. It is envisaged that the principal objects of the Council would be to determine and regulate terms and conditions of employment on sites in the engineering construction industry, to develop and maintain good standards of productivity and industrial relations and to provide a forum for the consideration of all matters of common interest to employers and employees in the industry. The Council would be funded by the employers and from any revenue producing activities which the Council might decide to undertake (eg a Holiday Stamp Scheme).

12.73. Recent discussions have included the electrical contractors and the thermal insulation contractors and it is hoped that the Council would embrace all mechanical, electrical and instrumentation construction, erection and installation work, including the associated thermal insulation. Close liaison would be maintained with the civil engineering contractors and unions representing their employees to help minimise inconsistencies.

12.74. The National Joint Council would determine basic conditions of employment (eg length of the basic workweek; conditions regulating overtime and shift working; basic rates of pay and allowances; holidays, etc); arrangements for the establishment of local Project Joint Councils; rules governing payments which may be agreed at site level; common procedures for the avoidance and settlement of disputes at all levels; a common disciplinary procedure; trade union facilities; abnormal conditions regulations; safety rules and procedures; arrangements for transfers, severance and redundancies; etc. Project Joint Councils would agree local detailed working arrangements within the basic common framework established and monitored by the NJC.

12.75. The CEGB has indicated that, if there is a further long delay over introduction of the National Agreement, Barnwood will on its own initiative apply the principles and objectives embodied in the current draft to future power station construction projects, through the introduction of comprehensive Site Agreements which would embody some of the concepts included in the Site Understanding recently achieved at Grain.

Direct labour

12.76. It would in principle be possible for the CEGB to seek to overcome certain of the problems of site construction work associated with the engagement of contractors by undertaking much of the work through direct labour. There are examples in North America and in other European countries of power station construction being undertaken in this way. Building a power station is a power engineering problem and the CEGB is a major employer of power engineers in England and Wales. Direct control of the construction labour force would enable the CEGB to establish common base rates and conditions payments, allowances and bonus rates. Work measurement could be standardised across the whole site for common bonus schemes, communications and co-ordination could be improved, common joint procedures for negotiation and consultation, etc could be established. In addition it might, subject to workforce mobility, be possible for the CEGB to create more continuity of employment and expertise on power station construction. At present, because the proportion of local labour employed on construction projects is very high and largely immobile, they tend to spin the work out to maintain their jobs, they are reluctant to work overtime and there are commonly acute productivity problems towards the end of a project.

12.77. The CEGB has considered this proposal, but there are some major difficulties which have led the Board so far to avoid proceeding with it. It would need to acquire additional construction management skills and industrial relations expertise in construction; there might be costly increases in pay levels in negotiating common terms for all site employees; a new structure for the CEGB's construction site agreements would duplicate arrangements outside the electricity supply industry; given the much greater immobility of construction staff nowadays, there might be problems over redundancies at project completion; the advantages of competitive tendering for erection would be lost; manufacturers would lose important erection experience; major industrial relations repercussions would be likely on the Board's relations with its existing staff and with trade unions (the Board's dealings with its own staff have been examined in Chapter 10); finally, if the Board moved into this area and then at some future date was required to change its policy, the resulting difficulties of contractors re-establishing organisational resources for site erection activities would be considerable.

Delays and cost increases in the construction of Nuclear Power Stations

12.78. In this section we are concerned with delays and cost increases only for the AGR stations. We have not undertaken any specific studies of Magnox stations since the last one was completed some ten years ago. It would appear that the origin of the delays and cost increases was euphoria induced by the apparent success of the Magnox stations at the time when an AGR programme was being conceived. This led to under-estimation of the problems associated with such technological developments as increasing gas temperatures from 450°C to 650°C and gas pressures by 100 per cent compared with early Magnox stations and, most important, leaping straight from the small 40 MW Windscale AGR to the 660 MW commercial AGR. Those in the nuclear and electricity supply industries to whom we have spoken all agree that less than adequate design work and testing was carried out and that it was a mistake to have accepted designs and proceeded with construction before designs were completed. Moreover, since as many designs were produced as there were consortia formed and contracts were awarded to each consortium, the task of creating organisations competent to execute the programme was under-estimated.

12.79. Construction of the first AGR station was started at Dungeness in January 1966 (the 'B' station), of the second at Hinkley Point ('B' station) in September 1967, of Hartlepool in October 1968, and of the first Heysham station in 1970. Of these only Hinkley Point B is operating, the first half since 1976 and the second since 1978, both at 80 per cent of their planned output. As we have noted above it is forecast that Dungeness B will be completed some 11 years late, Hartlepool eight years late and Heysham I five years late. Average costs to completion are forecast to double in real terms. Even the most satisfactory of the AGR designs has needed eight years for completion in both England and Scotland, compared with a planned time of five years, although it is now generally agreed that a more realistic target completion time would have been six years.

12.80. Again with hindsight it is clear from the views we have received that work on the AGRs has been at the frontiers of technology. The implication of this is that there were many components of the AGR which could not be fully tested before full-scale operation began, nor were relationships between the variables in the design sufficiently understood even to allow simulation of certain potentially damaging conditions. Nevertheless a full-scale prototype AGR was not built before proceeding to the programme. It is the CEGB's policy not to repeat that mistake in the current proposals for the future nuclear programme.

12.81. A further complication is that small errors of workmanship or failures of inspection can have much larger effects than they would in less complex structures, particularly when many components have to last for 30 years without possibility of repair or replacement if they fail. Such failures at Magnox stations are discussed in paragraphs 8.12 ff.

12.82. A final factor was consideration of safety. Safety standards rose during the long course of construction of these reactors and it was therefore possible to carry out modifications which would not have been so easy to effect if the original construction time had been adhered to. Furthermore we have been told that in some cases construction was started with the approval of the NII having been given in principle only on the understanding that a design solution was feasible but before the project consequences of meeting the safety standards had been fully worked out.

12.83. The cost and time penalties which followed this chain of events were exceedingly heavy. Indeed the cost of rectifying some of the individual difficulties in meeting new requirements ran into tens of millions of pounds and in one case was as much as five times the contractor's original estimate for the work. The CEGB has provided us with a broad analysis of the causes of these extra costs. They are set out for each station in Table 3.2 of Chapter 3. We have discussed these costs in greater detail with the CEGB and it has identified the specific technical cause in each case. They differ widely between stations and there is no clear pattern of a single fault repeating itself in all, or in a majority of, stations. Even where there is an apparently similar fault the engineering consequences can differ widely.

12.84. Some of the faults were quite small in themselves such as the failure during manufacture to drill a hole in a small proportion of components used unfortunately in hundreds of thousands, all of which had to be re-checked in situ. Some tasks were much larger, such as the need to demolish and rebuild complex concrete structures following re-design of the nuclear fuel route in order to meet the client's new safety requirements.

12.85. Labour disputes and low productivity during construction of nuclear stations have accounted for about 20 per cent of the delays experienced. The reasons for disputes were in some cases different from those at conventional stations. There are difficulties in managing large numbers of skilled men carrying out intricate work in confined spaces where protective clothing is required. Moreover it is natural that the morale of the workforce should be affected by delays caused by external factors and the frequent necessity to dismantle items of plant and demolish structures which were found to be unsatisfactory on safety or performance grounds.

Work content

12.86. For the reasons given above the work content of AGR stations has proved to be considerably greater than the original estimates. The Magnox station at Wylfa was completed in 1971 using 20 man-hours per kW. In 1967 the forecast for new AGRs was 15 man-hours per kW. Hinkley Point B was actually finished in 1978 using 14·5 man-hours per kW (at a design rating of 1250 MW). Up to the end of 1979 Dungeness B had absorbed 38·5 man-hours per kW, Hartlepool 24·2 and Heysham I 21·8. All three are now nearing completion. Heysham II, where construction has not yet started, is forecast to have a 45 per cent greater work content than Hinkley Point B.

12.87. Whilst the design of PWRs is different, overseas experience has shown that the work content of designing and constructing them has also increased substantially over the years. Between the PWRs of the 1960s and those of the 1970s Westinghouse (*Nuclear Energy* 1979, Vol 18, no 6) has noted increases in the engineering man-hours required per reactor from ½ million to 3½ million and in the number of drawings by a factor of 20. World-wide during that period it has been said that the average size of PWRs increased by 50 per cent to 1200 MW but labour man-hours per kW increased by 143 per cent and concrete poured by 89 per cent. It has also been reported in *Power Engineering* (April 1974 and January 1975) that planned construction man-hours for nuclear plants increased from 3 to 4 per kW in the mid 1960s to 11 to 12 for plants scheduled for commercial operation in the 1980s.

Nuclear safety

12.88. We paid particular attention to safety because it was argued to us by the CEGB as noted above that increased safety standards in the past had been responsible for a significant proportion of cost increases in completing AGRs. In the United Kingdom the duty of operating a nuclear plant in a safe manner is laid upon the licensee, in this case the CEGB. Before construction of a nuclear plant can begin the CEGB has to submit a safety case to the Nuclear Installation Inspectorate (NII) which is part of the Health and Safety Executive. In its design proposals to them it will incorporate such features as it judges will satisfy the NII and they have issued guidelines on the safety assessment principles for nuclear power reactors to help this process. The NII then either approve and issue the licence, ask for further information or suggest modifications to be made to the design. Approval to start construction does not confer approval to operate and the CEGB has to satisfy the NII again by various tests at various times before generation of electricity can begin.

12.89. It would appear that increases in safety standards in the past have followed from the responsible attitude of those accountable for safety, based on world-wide experience of operating reactors and world-wide pressures from those potentially affected by safety failures. Safety standards are discussed frequently between the regulatory authorities of the major countries of the world and between plant operators. A 'world view' therefore emerges. A typical example has been pressure for the inclusion of protection against earthquakes in new designs. This protection is now policy in Britain.

12.90. Safety standards can therefore be said to be settled by the interaction of a number of forces and it is not possible nor would it be fruitful to ascribe changes to any one source. We have investigated the increasing stringency of safety standards because of the past effect on construction time and cost which we have noted above and because of the potential effect if they were to become more stringent in the future. We have discovered no official analyses carried out in this country which attempt to establish relationships between safety and costs including cost consequences to the general public. Moreover such analyses as have been carried out operate under the technical difficulty that present radiation levels to which both operators and the general public are exposed are so low that changes in them cannot be detected statistically. It is not possible therefore to debate rationally whether a point exists beyond which it would not be sensible to raise standards further on economic or other grounds.

12.91. Both the CEGB and the NII have told us that they believe that the rate of increase in safety requirements is slowing down and that they are now approaching a limit. Moreover since the vast bulk of design work for the new AGR at Heysham II will have been completed before construction starts, approval of the design by the NII for the purpose of issuing the site licence will be likely to result in there being fewer changes to the plant for safety reasons during the construction period. Indeed the NII have told the CEGB that they know of no outstanding safety issues which require resolution before the consent to the reactor vessel construction is granted and that they hope to avoid the need to require a further consent until the time of pressure test on the vessel (which takes place near the end of the construction process). However AGR refuelling still raises safety issues. AGRs can be safely refuelled off-load at a high cost, but safe on-load refuelling has yet to be demonstrated.

12.92. It will be some years before all safety issues associated with the proposed PWR at Sizewell are resolved to the satisfaction of the NII. Indeed the public inquiry has yet to take place. However, the NII believe that if appropriate safety aspects are included in designs from the beginning, the cost of safety is predictable, although the NNC remain sceptical on this point. Safety requirements also affect maintenance and the number of personnel needed for maintenance and in particular for in-service inspection.

Contractual Relationships in Nuclear Construction

12.93. The first nuclear stations (Magnox) were constructed by consortia using comprehensive contracts of a turnkey type. Although the consortia were not themselves manufacturers of nuclear plant, their parent companies were. The history of the various consortia is set out in tabular form in Appendix 26.

12.94. Following the precedent of the Magnox programme, competitive tenders for the construction of AGR stations were sought from a number of consortia. 'Comprehensive' contracts were awarded as follows:

Atomic Power Constructions Limited (APC) — Dungeness B

The Nuclear Power Group Limited (TNPG)—Hinkley Point B (and Hunterston B in Scotland)

British Nuclear Design and Construction Limited (BNDC) — Hartlepool
— Heysham I

There were substantial differences between the designs of the three consortia. Only Hinkley Point B and Hunterston B have been commissioned.

12.95. The contracts made the consortia responsible to the CEGB for design, procurement, contract supervision and construction management. In many cases member companies of the consortia or their subsidiaries acted as sub-contractors to the consortia for the manufacture of major plant items such as turbines. Since none of the consortia had more than £1½ million of capital whilst they were planning to undertake work up to a hundred times that amount, joint and several guarantees were given by the parent companies.

12.96. By 1970 the contract for Dungeness 'B' had run into severe technical and financial difficulties and APC became potentially insolvent. The CEGB ultimately purchased APC for a token sum and the former shareholders of APC paid penalties to the CEGB under their guarantees. Arrangements were then made for BNDC to continue the work as manager of APC but ultimately, in 1976, the arrangement had to be modified when APC (as a wholly-owned subsidiary of the CEGB) took the job over and placed two Agency Contracts, one with NPC for the construction of the nuclear island (see paragraph 12.99) and one with Barnwood for the conventional plant. In the early 1970s the other consortia, BNDC and TNPG, were also experiencing significant problems at the other four AGR sites (including the site in Scotland); no further orders for nuclear stations were in prospect and the economic situation of the construction industry was deteriorating.

12.97. In view of this, in 1973 the Government was instrumental in setting up the National Nuclear Corporation with £10 million share capital. This was divided between the UKAEA, holding shares on behalf of the Government, GEC and British Nuclear Associates Ltd, a grouping of seven engineering companies. NNC established the Nuclear Power Company as its operating arm. By 1975 the NPC had taken over the surviving consortia BNDC and TNPG under the names of NPC (Risley) Ltd and NPC (Whetstone) Ltd. The power station contracts were re-negotiated with a target cost arrangement under which the Board would effectively reimburse the total costs to completion, but NNC had a limited liability under profit and loss sharing arrangements which could have an effect on the amount of the fee it earned. Target bonuses for timely completion and operation were also incorporated. NNC's ability to meet its potential liabilities was in any case limited by its share capital of £10 million: and there were no guarantees from its shareholders. GEC supplied supervisory management under a contract with NNC which imposed no financial liability upon GEC.

12.98. Cost increases as a result of major modifications and delays at Hartlepool and Heysham led in 1979 to the CEGB's seeking closer involvement with NNC in the management of these contracts. As part of a new contractual relationship a Joint Supervisory Board for each project was set up, composed of senior NNC and CEGB staff. Full information on technical and engineering progress and on expenditure by sub-contractors is now available to the CEGB staff concerned and is considered by the Joint Supervisory Board. There is an agreed level of delegation between the CEGB and the NNC. The letting of further contracts, and authorising of payments are subject to this procedure. The checking of progress is a joint project management role with the CEGB having access to sub-contractors.

12.99. In 1979 NNC was awarded contracts to design the nuclear island[1] for Heysham II AGR station and Torness AGR station for the SSEB.

12.100. In December 1980, following sustained pressure by the CEGB, NNC became a single tier company by absorbing its operating companies and the GEC Supervisory Agreement mentioned above was terminated. This did not affect the arrangements described in paragraph 12.98. NNC's capital remains £10 million.

12.101. This history illustrates the severe impact that technical problems have had on contract structures and indeed on the viability of the contractors. The arrangements for existing sites involve NNC and Barnwood in joint managerial roles and are not those which would have been preferred by any of the parties had they been starting afresh. Nevertheless they appear to be the only practical way of finishing work which has proved so troublesome in the past and where the consequences of decisions taken 15 years ago are still being experienced.

The roles of Barnwood and the NNC in the future nuclear programme

12.102. Civil engineering and turbo-generator contracts for Heysham II have been let by the CEGB and major contracts for the construction of the Heysham II nuclear island and for the design of a PWR station are under

[1] The 'nuclear island' is that part of a nuclear station comprising the nuclear reactor, the steam generation equipment, the associated plants for coolant composition control, water treatment etc, and the associated plants for control and support.

negotiation. In view, however, of NNC's inability to accept liability commensurate with the size of contracts involved, it is the CEGB's intention that it will place direct contracts with the suppliers of plant for the nuclear island with NNC, acting as the Board's agent, exercising a clearly defined role including powers and duties to be specified by the CEGB. In the Board's view this arrangement should provide necessary and proper protection from failures by contractors associated with the nuclear island plant, who will have a direct liability to the Board, so protecting the Board's position in a way that is in line with practice in other industries. We are also told that the CEGB is discussing with NNC the extent of its liability to the CEGB as agents given that NNC does not appear to be contemplating an increase in its £10 million capital.

12.103. The various parties potentially involved in ordering, designing, constructing and ensuring the safety of a PWR have been discussing their respective roles in the light of a statement in the House of Commons made by the Secretary of State for Energy in December 1979. He said that the NNC should have 'total project management responsibility' for the proposed PWR station. Furthermore the Government attached 'importance to a steady build-up of the NNC into a strong and independent design and construction company, fully able to supply nuclear power stations at home and abroad'.

12.104. The first understanding for provision of a PWR was entered into between the United Kingdom Atomic Energy Authority (UKAEA), the CEGB and the NNC in July 1980. It provided for a division of responsibilities up to the time of the public inquiry:

- The NNC would be responsible for the preparation of the design and the associated safety statements (the 'safety case').
- The CEGB would be responsible for assessing the design and the safety case and submitting the latter to the NII. It would also prepare the case for the public inquiry and conduct the case at that inquiry.
- The UKAEA would make arrangements for the conduct of a programme of work in the fields of research, development and demonstration, necessary for United Kingdom purposes, to supplement the information available under the Westinghouse licence agreement and from other sources. (NNC have been licensed by Westinghouse to manufacture and supply a PWR NSSS.[1] It does not necessarily have to be manufactured by Westinghouse.)

12.105. Whilst NNC has started to design the proposed PWR station under the terms of a letter of intent from the CEGB, and will in turn sub-contract some of this work to Barnwood, at the time of writing formal discussions on arrangements for constructing the PWR have not yet begun. However, from discussions with the parties it is possible to envisage a range of alternatives from NNC's acting as agent to the CEGB, as proposed for Heysham II, to its acting as main contractors. The same questions concerning the limited liability of NNC would arise as for Heysham II.

[1] Nuclear Steam Supply System.

12.106. A third party, the American consulting engineers Bechtel, has been awarded a contract by NNC to act as the latter's consultants. Initially the services may be provided in specific areas of the design and definition of the planning and procedures for construction of a PWR. During construction additional help would be given on construction methods. Bechtel has extensive practical experience of planning PWRs and bringing them into operation in the USA, experience which we are told is likely to prove essential in this case. It complements the experience of Westinghouse in design, manufacture and construction of the NSSS.

12.107. In other countries various forms of arrangement are used for constructing power stations including PWR stations, and other large projects. We refer to the three principal forms here.

12.108. One of the most common is to employ an 'architect/engineer'. An architect/engineer for construction projects is often an independent consulting engineer who acts as the agent of the client for overall design and layout of the project, sometimes placing the contract and often supervising construction. The CEGB employs such firms for civil engineering design but otherwise for conventional stations uses Barnwood as its own architect/engineer. In other countries, whether this role is performed in-house or by a consultant usually depends upon the size of the client organisation and whether it is publicly or privately owned. In North America large electricity utilities such as Pacific Gas and Electric, American Power Corporation, Ontario Hydro, and the Tennessee Valley Authority, and in Europe Electricité de France, act as their own architect/engineers. Indeed the last three go further and employ their own construction labour force.

12.109. The second principal form of arrangement is the employment of an 'engineer/constructor'. This is an independent professional firm which not only acts as architect/engineer, but also contracts with the client to construct the power station. In order to do so the engineer/constructor may employ his own labour force or a sub-contractor or use 'free issue' labour provided by the client. However, in these circumstances the firms manufacturing the major components such as boilers and turbines usually have a direct contractual relationship with the client. The engineer/constructor places and supervises these contracts as the client's agent, but may procure smaller hardware items as a principal. When the engineer/constructor acts as the client's agent, any guarantees of the performance of proprietary equipment or liquidated damages in lieu are available directly to the client. In the United States as many as six firms might compete for such a role on a power station project.

12.110. The third main form of arrangement is the use of a 'comprehensive' contractor. This is common in the oil, gas chemical, computer and telecommunication industries. A large company or a consortium of companies usually with facilities to manufacture the largest plant components of the project in question, eg the boilers or turbines, contracts with the client in return for a lump sum to fulfil the engineer/constructor role and to manufacture the plant, some himself, and some by sub-contract, but in each case giving performance guarantees to the client. Such forms of contract are only appropriate for established technologies.

The Role of Barnwood

12.111. A number of organisations have made criticisms to us of the role of Barnwood. The first is of excessive checking of contractors' designs to see that they conform to the CEGB's specifications. We have drawn attention in paragraph 8.25 to the effects of merely assuming that a design will meet a performance specification and we think that the Board is justified in being exacting in its checks.

12.112. Another comment we received was that Barnwood was tough in negotiation, engaging in a continuing debate over the fine points of costs, specifications and performance. We ourselves have seen cases where such negotiations have produced valuable savings of over 25 per cent of the contract price, amounting in one instance to £24 million, and we see no reason to discourage them.

12.113. A further set of criticisms made to us was that Barnwood:

(*a*) over-specified plant items to be supplied and thereby did not leave sufficient freedom to the supplier's designers to achieve the desired performance of the equipment at a reasonable cost;

(*b*) in its specifications required a higher quality than that which would in the supplier's view have been perfectly adequate; and

(*c*) used standards which differed unnecessarily from British Standards and those of the International Standards Organisation.

12.114. Only one concrete example of criticism (*a*) above in the range of items handled by Barnwood has been quoted to us—the choice of a six-flow instead of a four-flow turbine for Heysham II power station. The Central Policy Review Staff has already examined this question for Ministers and we do not therefore propose to comment further.

12.115. Because of criticism (*b*) above we studied the CEGB's procedures for choosing design parameters for its power stations. We have been impressed by the number of models used for the optimisation of different parts of the design and the range of the engineering and economic factors taken into account. In particular savings were achieved in assessing with the contractors designs for Hartlepool and Heysham I nuclear stations. We are satisfied that these calculations are directed towards the stated objective of minimising the lifetime cost of power stations.

12.116. It is also the CEGB's settled policy to use British Standards where they exist, and to support national moves to harmonise British and International Standards. In view of item (*c*) above we examined samples of the CEGB's standards and whilst our examination was only as detailed as time permitted, they appeared to differ from the appropriate British Standard only in that they specified certain matters which the British Standard left unspecified. It is only in the case of switchgear and certain transformers that the CEGB's and indeed the Electricity Supply Industry's standards differ significantly from those accepted as International Standards. In the past this has been due to the International Standard's specifically catering for less concentrated electricity supply systems. Recent changes in International Standards have allowed both the International and the CEGB's standards to be more closely aligned.

12.117. We have also been impressed by the results which Barnwood has obtained by insisting on the adoption by contractors of improved quality assurance procedures for the manufacture of power station equipment.

12.118. The criticism has also been made to us that the staff of Barnwood is too large, even though it might justifiably in the past have attained its current size because of the expanding power station construction programme of the 1960s. Fewer stations were now being built than at that time but Barnwood's size had not been reduced. We have noted in paragraph 5.15 and shown in Figure 12.1 that since 1974 the workload of Barnwood, if measured by the volume of construction work in hand (in MW), has in fact been increasing. The number of staff must be related in part to the number of stations under construction and the volume of work on hand and therefore in so far as that relation holds there is no particular reason why numbers should have been reduced in the recent past. The number of staff fell by approximately 220 following formation of the Division in 1970. Since that time, for a variety of reasons, including the backlog of construction work, staffing levels have not changed significantly. For the future, however, a large decline in staff numbers is expected, although its extent will depend on the matters discussed in paragraphs 12.121 ff.

Internal reviews of the role of Barnwood

12.119. We have examined the process whereby Barnwood plans and controls its own operations and staffing. The planning system is identical to that of other divisions and regions of the CEGB as described in Chapter 6. Plans are produced up to five years ahead and revised annually. Special topics within the plan are reviewed regularly at meetings of the Directors of the Division. There is also a rolling manpower planning programme as part of the annual planning process.

12.120. In addition to the regular reviews of separate functions at Barnwood, periodically its complete role is reviewed by the Board. The last review in 1979 resulted in the current structure and duties set out at the beginning of this chapter and in Appendix 24. Another review is in progress in the light of the proposed programme for constructing nuclear power stations and against the background of reduced forecasts of electricity demand.

12.121. The numbers of staff at Barnwood may be affected by the choice of nuclear or conventional stations, by the type of nuclear power unit finally decided upon for the long-term programme and by the extent of replication of design. Moreover it now seems likely that it will be more economic to extend the life of some coal-fired stations, the thermal efficiency of which is satisfactory, than to build new ones. Life extension would obviously reduce the number of staff required to plan and control new construction. On the other hand refurbishment might be more economically planned centrally by Barnwood rather than in each Region. Moreover technical problems which are still arising in Magnox stations continue to bring additional work. Further work will come from planning the closure of these stations when they reach the end of their lives. Nuclear safety has also required increased staff at Barnwood in recent years. The biggest effect on staff numbers is, however, likely to follow from decisions on the relationship between Barnwood and the NNC in controlling the design and construction of nuclear stations. If the whole future nuclear programme were based on replicated designs of PWRs and NNC were to act as main contractors for their construction, the outcome for Barnwood could be a cut in staff of up to 50 per cent.

12.122. The CEGB is well aware of the effects of the various options being discussed, but no firm decision can be taken until the nature of the nuclear programme, its size, the selection of reactor types and relations with NNC have all been determined, however difficult this may be for the staff concerned both at the NNC and at Barnwood. In recognition of this situation, the Division has imposed a virtual freeze on recruitment since 1979, allowing numbers to decline by controlled natural wastage.

Conclusions and Recommendations

Industrial relations

12.123. Many of the weaknesses and failings on power station construction sites remain but some important progress has been made over the past 18 months. In particular, the steps taken by the CEGB to improve co-ordination and control at Ince, Littlebrook, Grain and Drax are very much to be welcomed. There has also been some progress towards the long delayed National Agreement for construction sites first recommended by NEDO in 1970. If such an agreement were to be concluded, it would have a beneficial effect on these sites because of the multiplicity of agreements hitherto.

12.124. As it is still uncertain whether negotiations for a National Site Agreement can be brought to an early and successful conclusion, we recommend that the CEGB should use its recent experience at Grain and Drax to produce and establish its own model site agreement. It is important that it should initiate this process before it contracts for the construction of a new power station.

Contractual relations and site management

12.125. Previous inquiries have ranged over the whole gamut of ways of managing the construction of power stations. Over the years the CEGB has pursued a number of them, often in response to the recommendations of a particular inquiry. Nevertheless, delays continue and costs increase. We have, however, noted the changes made by the CEGB for the most recent contracts. These have involved re-negotiating some reimbursable contracts as lump sum, introducing the key-date system for the better motivation of contractors, setting the number of main contractors on site at a number related to the ability of each to manage a given labour force, and establishing management groups. Although it will be some years before it can be demonstrated whether these measures have worked, we welcome them as examples of the tighter control now being exercised.

Technical preparation

12.126. We also believe that a policy of settling design before construction starts and letting separate design contracts is right. It is to be hoped that, together with a policy of replication for major plant items and component standardisation, it will do much to overcome delays caused in the past by adopting too many new designs of major equipment in one project without adequate proving and then having to make the consequential engineering changes.

Nuclear stations

12.127. The design and construction of nuclear power stations have presented the severe problems in the past which we have noted in paragraphs 12.78 to 12.87. These must be overcome if the nuclear programme is to be pursued with success. Nevertheless, in designing and constructing nuclear reactors for the safe generation of electricity one is working at the limits of known technology. It follows therefore that no one can guarantee that some flaw or design error will not occur which will cause a year's delay or millions of pounds of extra cost or that safety requirements may not increase and have a similar effect.

12.128. The history of nuclear power station construction in England and Wales to date—and so far as we can tell in other countries as well—shows clearly that no arrangement has yet been devised whereby such risks can be borne by any party other than the client—in this case the CEGB and ultimately its customers. Indeed the NNC has told us that if it were the main contractor for construction of a PWR, although its fee would depend partly on its success, the CEGB and by implication consumers of electricity would have to bear most of the risks. Moreover, it would wish any contracts into which it entered to be reimbursable. We also note that not even the largest American companies in this field are able to give guarantees of total nuclear station performance. This is because if mistakes are made in integrating the design of the whole station, their effects could be measured in many millions of pounds and there could be no recourse to the manufacturers of individual plant items.

12.129. We believe that the proposed arrangement for Heysham II, whereby NNC would act as the CEGB's agent rather than as a contractor, is a realistic approach to the problem of performance risk which recognises the inability of NNC to meet liabilities beyond its fee and capital without guarantees from its shareholders.

12.130. However, we recommend that in letting all future contracts for nuclear stations, and in particular the first one for a PWR, the CEGB should be guided by the following principles:

(1) The CEGB should ascertain from as many potential suppliers and contractors as possible both here and abroad, whether any of them would be willing to bear any of the performance risks. If so the CEGB would need to weigh the terms upon which they might be borne against the probable costs of remedial action it might have to take itself or the long-term effects of letting performance remain below standard. To the extent that it is not economic for the risks to be borne by anyone else, it must be recognised that part of the cost of the nuclear programme is the bearing of such risks by the CEGB and hence by consumers of electricity.

(2) If the main contractor is to have such limited resources as those we have described above for the NNC, guarantees of equipment performance should be available directly to the CEGB.

(3) As many contracts as possible should be let on a firm price basis, with the appropriate price variation clauses and use of the CEGB's key-date incentive system.

(4) Contractual responsibility and size of contracts placed should be related to the financial resources of the contractor and the risk he is willing and able to bear.

(5) There should be unified control over the execution of projects. We believe that this was what the Secretary of State was seeking in his statement quoted in paragraph 12.103.

12.131. We believe that this last principle is important because in the past there have been too many separate organisations involved in constructing nuclear stations, related in contract structures of great complexity. It is therefore essential that any new arrangements should set out much more simply the responsibilities of the different parties for eg design, execution and supervision of the works. One of the proposed arrangements for the first PWR contradicts this principle in so far as the NNC, which is supposed to be the main contractor, is to sub-contract part of the design work back to the CEGB itself. Furthermore it is proposed that responsibility for managing the construction of Heysham II will be split between Barnwood for the conventional part and NNC for the nuclear island.

12.132. Whereas the proposed contractual arrangements described to us for Heysham II follow principle (2) above, this would not necessarily be true of the alternative put forward for the first PWR which envisages NNC becoming the main contractor.

12.133. We have included principle (3) because we doubt whether the use of reimbursable main or subsidiary contracts would be sufficient to motivate contractors to work to time and to cost. Our doubts are based upon the plain evidence of past performance when such contracts were in use.

12.134. It may be that the contracting arrangements in use in other countries which we have described in paragraphs 12.108 ff are effective in giving better protection to the client than the CEGB has obtained hitherto. Whilst it is possible to discuss in detail their applicability to the construction of power stations in England and Wales, we prefer to leave this to the CEGB. However all the material we have seen points to the conclusion that if the CEGB is to continue to build nuclear stations, there is no certainty that the risks associated with construction and performance can be borne otherwise than by the CEGB and through it by the consumer.

CHAPTER 13

Conclusions

1. Our terms of reference require us to report on the question whether, in operating its system, the Board could, without reducing the standard of service provided, improve its efficiency so as to be able to reduce its costs or mitigate the effect of any increases in costs.

2. Our detailed conclusions and recommendations are summarised below:

	Recommendation Number		*Paragraph Number*
Financial Framework		We believe that the Board's cost minimisation programme will help to limit increases in costs. Nevertheless the Board's attempt to meet its financial target is bound to lead to a considerable increase in the Bulk Supply Tariff over the next two years, to levels somewhat higher than contemplated in the present plans of the industry.	3.87
		The Board has a sophisticated and well-documented system of revenue cost control, which the responsible officers operate in an efficient manner.	3.89
		Internal audit is pursued effectively, and reinforces and supports the external auditors in their statutory role.	3.92
		The Board's cash management is competent.	3.93
		The procedures for approval of capital spending are well defined and properly observed.	3.95
		Costs of work in progress are properly monitored; and	3.96
		contract negotiation and claims under contracts are skilfully pursued by staff well qualified for those tasks.	3.97
Investment Background		Demand forecasting by the Board and the Electricity Supply Industry as a whole has been seriously inaccurate and has led to premature orders for new plant which have increased costs. The Board's forecasting methods have recently improved.	4.64
		The Bulk Supply Tariff is intended to reflect long-run marginal costs; but we believe that the way this principle is being applied creates the danger that the basis of the BST may become arbitrary.	4.65
	1	**We recommend that Demand Charges should be based on the Board's plans for the development of its generating capacity over the next ten to fifteen years.**	
	2	**We also recommend that Demand Charges should be based on a central estimate of the net effective cost of new plant.**	4.67
		We do not think that the influence which the Board wishes to exert through the BST is adequately reflected in Area Boards' tariffs;	4.68
	3	**and we recommend more effective consultation between CEGB and the Area Boards on tariffs.**	
		A reduction in the generation security standard would reduce the Board's costs in the long-run and might perhaps be made without perceptibly affecting the standard of service provided	4.69

Recommendation Number | *Paragraph Number*

to consumers, who suffer interruptions of sup-
ply much more frequently from other causes
than generation shortage. We believe that the 4.71
matter requires further study under the aegis
of the Electricity Council. We welcome the
Board's intention to reconsider the planning
margin before it again becomes relevant to 4.72
plant orders.

Investment Decisions

The Board has developed computer programs 5.134
to permit comprehensive assessments of the
effects of particular investment projects on the
basis of specific estimates and assumptions; but
the value of these assessments depends on the
validity of the assumptions used as inputs. We
are not satisfied that all the assumptions relat- 5.140
ing to coal price and availability are plausible
4 or mutually consistent. **We therefore recom-** 5.143
mend that the Board should develop an internally
consistent view of future domestic and imported
coal prices and availability. We consider that 5.144
further work on the future trend of nuclear fuel
cycle costs is also necessary.

In estimating the net effective cost of new gene-
ration projects, the Board's practice of using
targets or limiting values for construction costs
and time and for some of the assumptions
about new plant performance means that the
'basic' NEC is not a central estimate. **We** 5.146
5 **recommend that explicit account should be taken**
of market conditions in supply of plant and of
6 **relative price effects during construction. We** 5.147
recommend that the Board should consider
adopting a larger start-to-finish allowance for
7 **nuclear power stations. We recommend that the** 5.149
process of estimating construction times should
be improved as a matter of urgency. We believe
that experience to date with gas-cooled reactor 5.150
systems suggests a more conservative estimate
than 100 per cent as the central estimate for
output rating until the technology involved is
better established. **On the period required to**
8 **attain full rating and availability, we recommend** 5.152
that a realistic central estimate should reflect
past difficulties.

We are not satisfied that the sensitivity analysis
shown in appraisal documents goes far enough,
particularly in the presentation of results out-
side the Board, and as a minimum the Board 5.160
should develop its sensitivity analysis in the di-
9 rections we have indicated. **We recommend,** 5.161
however, the further step of reorienting the
approach altogether and presenting outcomes
associated with the central estimates of all the
relevant determining variables. Either of these 5.173
courses should lead to a more dependable
assessment of the economic case for nuclear
projects than that presented for Heysham II,
which may have unjustifiably reinforced the
strategic case for the order. If the Board's costs
are to be minimised it is important that future 5.174
projects should be assessed on more reliable
economic grounds.

Recommendation Number — *Paragraph Number*

Operational Planning

The merit order based on system marginal 6.105
costing is an appropriate method of cost
minimisation, although the current
computer-based system does not guarantee a
true optimal solution. We have indicated two 6.107
areas of development which may warrant
study.

We are satisfied that the Board has an effective
operational planning system and that the out- 6.108
turns are adequately monitored.

The procedures for short-term planning of 6.109
generation are effective in maintaining security
of supply at a cost consistent with good mana-
gement. The Board is obtaining cost savings 6.110
at the margin in a number of ways.

10 **We recommend that the Board should undertake** 6.111
a comprehensive cost/benefit study of central on-
line scheduling and despatch of plant, and if the
net benefits are consistent with the Board's
normal criteria, it should develop a plan for full
implementation.

Fuel Procurement

The Board's costs could have been lower if
more use had been made of opportunities to 7.112
import coal for some of its power stations. We
see obvious objections to the understanding
between the CEGB and the NCB because the
use of the retail price index is not related to
changes in the costs of the supplier, and 7.114
because of the absence of any relationship with
11 long-run marginal cost. **We recommend that the**
CEGB should aim to improve the terms and
increase the duration of the understanding. In
the agreement between the CEGB and BR, **we**
consider the exclusive dealing arrangement is a 7.115
major restriction on competition from alternative
12 **forms of transport, and we recommend that it**
13 **be abandoned. We also recommend that the price** 7.116
variation mechanism in the agreement should be
revised so as to give BR a greater inducement
to limit growth of their costs, and to enable the
CEGB to benefit from improvements in producti-
vity in rail carriage of coal. In its procurement 7.117
of oil the Board is efficient and professional;
minimum quantity clauses have had only a
minor effect on costs.

The Board has secured long-term supplies of 7.118
uranium at prices lower than those on the spot
14 market. **We recommend that the Board should**
seek to negotiate 'call-off' clauses so as to be 7.119
able to match supplies to actual requirements,
and should persist with a policy of diversifying 7.120
its sources of supply. The Board's decision to 7.122
obtain most of its uranium enrichment services
from the centrifuge process should give lower
costs in the long-run; and the recent renegotia-
tion of terms with Urenco should help to secure
the benefit of this in lower prices. The relation- 7.123
ship between CEGB and BNFL presents diffi-
culties owing to the lack of competition. Since
the CEGB underwrites so much of BNFL's in-
15 vestment **we recommend that consideration be**

Recommendation Number		*Paragraph Number*
	given to appointing one or more representatives of the CEGB to the BNFL board. The terms of trading provide for BNFL to provide specified information; and while this is satisfactory as regards operating costs, the situation is less so as regards investment projects.	7.124
	This, and the Board's own tardiness in costing appropriate alternative options, has vitiated a part of the investment appraisal for AGR power stations.	7.125
16	**We recommend that the Board should remedy this urgently.** We hope that the Board will continue to press for improvements in the terms of trading, and will resume the search for standard efficiency norms.	7.126
17	**We recommend that if a PWR programme is undertaken, the CEGB should seek competitive tenders from BNFL and foreign organisations for supply and reprocessing of the fuel.**	7.128
Availability and Maintenance	We are satisfied that maintenance of power stations is well managed, and we note that availability has improved in recent years.	8.43
	However, the systems for reporting shortcomings of equipment are fragmented.	8.44
	Improved reporting systems could enable the CEGB's operating experience to be taken more fully into account in new plant designs.	8.45
18	**We recommend that full quality assurance procedures should be introduced at large power stations, with a nominated person independent of other functions being responsible for quality.**	8.46
Purchase and stocking of Plant spares	In matters of purchasing and stock control the Board has relied upon the judgment of its engineers. This policy has helped to maintain a high level of availability, but has obscured the need and reduced the motivation for operational research studies and more advanced methods of stock control.	9.31 9.32
19	**We recommend that the Board should develop such methods, and as an interim measure it should charge interest to Regions on the value of stocks held.**	9.33
20	**We recommend also that Regions should systematically record the number and percentages of prices challenged on single tender contracts, together with prices asked and prices to be paid, and then compare the results.**	9.35
21	**On national spares, we recommend that the Board should consider whether its use of a 15 per cent rate of return and a 3-year pay back is causing under-investment in national spares.**	9.37
	For both regional and national spares, wherever fully competitive tendering is not available, the systematic monitoring and negotiation of manufacturing costs is likely to be the best course of action.	9.38
22	**We recommend increased use of standard designs owned by the CEGB to permit competitive tendering for, and reduced holdings of, spares.**	9.39
Industrial Relations and efficient use of manpower	The Board's personnel function is well organised and co-ordinated. Industrial relations are generally good. There has been a reduction in manual employees represented on the NJIC, associated with flexible working practices and work measurement, and output per head has increased. We have found some	10.59 10.60 10.63

Recommendation Number		*Paragraph Number*
	evidence of overgrading among engineering staff represented on the NJB and some indications of reluctance to accept and co-operate in rationalisation of their grading structure. We believe that the management should put forward a timetable for the introduction of job evaluation; and it is important that NJB staff should co-operate in measures to improve the efficiency of their utilisation and deployment.	10.64
23	We believe there is scope for greater efficiency of NJC manpower utilisation, and **we recommend the further implementation of the established clerical work measurement systems and the application of modern office technology.**	10.65
	There may be too many management grades.	10.66.
	In recent years the Board's labour costs have been rising faster than the national average; the Board and all the trade unions in the industry need to co-operate in securing further improvements in the efficiency with which the industry's manpower is used.	10.68

Management Information Systems

	The Board's main management information systems provide adequate information for operational control and functional management control.	11.50
	The systems are not over-elaborate and for some purposes there may be a case for additional precision. However, the Board has no information system which brings together information across all resources so as to give an integrated approach to strategic and corporate planning; at station level there is no uniform system to serve in a convenient form the needs of general management; and we have not found the concept of exception reporting well developed.	11.51
	The Board's management information systems have never been subject to a comprehensive review, and we believe that with the recent establishment of a central computing directorate and technical changes now taking place this is an appropriate time to review the Board's systems and to produce a strategy for the next decade.	11.52
24	**We recommend that such a review should pay particular attention to:**	11.54

(*a*) **the needs of corporate and strategic planning;**

(*b*) **the needs of general management, especially at station level;**

(*c*) **the definition of decision-oriented needs at all levels; and**

(*d*) **the use of exception reporting in management control; and that the Board should take the necessary action to secure any potential benefits which may be identified.**

Construction of Power Stations

	The weaknesses and failings on power station construction sites discussed in earlier reports still exist; but some important progress in site labour relations and productivity has been made recently.	12.123
25	**So long as there is no national agreement for construction sites we recommend that the CEGB should seek to introduce a model agreement for use on its sites.**	12.124
	We welcome the measures recently introduced in connection	12.125

Recommendation Number		*Paragraph Number*
	with contruction contracts, while we recognise that it will be some years before it can be demonstrated whether these measures have worked.	
	The current policy of letting separate design contracts and settling design before construction begins should avoid some causes of delay.	12.126
	The special problems associated with nuclear power stations must be solved if the nuclear programme is to be pursued. No arrangement has yet been devised whereby the risks can be borne by any party other than the CEGB and ultimately its customers.	12.127
	We therefore regard it as appropriate that the NNC should act as the CEGB's agent in procuring plant for the nuclear island at Heysham II.	12.129
26	**We recommend principles by which we consider the CEGB should be guided in letting future contracts for nuclear power stations.**	12.130
	The contractual arrangements used in other countries may give better protection to the client; but we doubt whether there is any way in which the risks associated with construction can be removed from his shoulders.	12.134

3. Some of the topics mentioned in this summary deserve further comment of a more general character. We have shown in Chapter 7 how important the CEGB, the NCB and BR are to each other. Where nationalised industries, each having a virtual monopoly, deal with each other as these industries do, the purchaser may not resist the seller's demands as vigorously as it ought, since it can pass on its costs to its customers. Also there can be no certainty that the bargains which they strike will lead to the most efficient use of resources. In its purchase of coal, the CEGB cannot be at all confident that the charges which it pays are related to the costs incurred in providing the fuel and transport which it requires. It knows no more about the National Coal Board's costs than it can glean from the NCB's Annual Report and Accounts; while as to the carriage of coal by rail, British Railways admit that they do not themselves know the costs of carrying coal over various distances, and therefore the rates charged are not systematically related to the costs incurred. In respect of nuclear fuel services the situation is not quite so bad, since BNFL does disclose its costs to the CEGB in some detail, and there are other fuel processors in the world whose charges can be compared, although there remains much uncertainty about the eventual costs of oxide fuel reprocessing.

4. This inter-relationship between nationalised industries raises important issues of public policy about their respective costs and prices. Some of these issues lie beyond our immediate terms of reference, but we are bound to say that the public interest in these circumstances requires at least a fuller disclosure of costs, so that all customers will be better able to judge whether prices really represent the resource costs of supplying them, and whether one industry is subsidising another.

5. Given this background, it is not surprising that confidence between the CEGB and the NCB has been lacking. We therefore recommend that the Government should give fresh thought to the objectives set for nationalised

industries which deal largely with each other. If, for example, it is considered to be in the national interest that high-cost coalfields shall remain open in the medium term, this might be better done by adjusting the financial objective of the NCB than by raising the price of coal and so making users of coal and electricity pay prices set above long-run marginal costs.

6. Coal has always been the CEGB's principal fuel. It is natural that the Board should seek alternative fuels. In the past this consideration has prompted the CEGB to build oil-fired stations; and now that the price of oil has risen above that of coal, the CEGB wishes to embark on a programme of nuclear power stations, as much for the sake of diversification of fuel supply as in the belief that early stations in the programme will generate power more cheaply than coal-fired stations. However, it is necessary to guard against the danger that the present coal price policy may make nuclear power appear to offer an economic advantage which it might not have if coal were priced at long-run marginal cost. We deal with the insufficiency of the Board's investment appraisal in paragraph 14.

7. Our terms of reference call upon us to examine five areas of the Board's activities in particular:

(*a*) its internal cost control and project control systems;

(*b*) its management information systems;

(*c*) its purchasing policies and methods of stock control;

(*d*) its management of plant maintenance and the effect of programmes for plant maintenance on plant availability; and

(*e*) the planning and appraisal of new investment, and its ability to carry out its proposals for such investment within the cost and the time estimated.

We are to say whether, in relation to any matter within these areas, the Board is pursuing a course of conduct which operates against the public interest.

8. We consider that the Board has not been pursuing a course of conduct which operates against the public interest in respect of its internal cost control and project control systems, its management information systems, or its methods of stock control.

9. However, in respect of its purchasing policies we feel bound to conclude that the Board could have had lower costs in recent years if it had been free to pursue the objective of cost reduction by every means available. First, the Board has not imported as much coal as it could have done at prices lower than it was paying for NCB coal; and it has not entered into long-term contracts for coal imports. At times the Board has been prevented from importing coal; and the knowledge that such restrictions might be imposed again has naturally affected its approach to planning for imports.

10. The Board has also pursued a 'buy British' policy in its procurement of plant. With only small exceptions it has placed its orders with the home industry, in the belief that it was in its own long-term interest to do so. If the Board is to build a number of stations with pressurised water reactors,

it may be another matter, since specialised facilities for the building of components of the 'nuclear island' of a PWR station already exist in other countries. The investment necessary for establishment of such facilities in the UK would be likely to make British components more expensive than imported components. If it is to be Government policy that a British capability for building such components be established, it does not follow that this should be done at the expense of the electricity supply industry and its customers.

11. Another reason why the Board's costs are not now, and are unlikely to be in the future, as low as they could be, is that twice in the past decade, at the Government's request, the Board has ordered a power station 'in advance of need', namely Ince B and Drax completion. The facts show that a power station ordered in such circumstances is unusually expensive. Ince B was estimated to cost £110 per kilowatt, substantially more than Grain (£70) before and Littlebrook D (£91) after it; and tenders for Drax completion, at £342 per kilowatt, were substantially higher than had been expected.[1] In each case the Government agreed to pay compensation to the Board for incurring capital charges earlier than necessary. It is already clear that the compensation for Drax completion, which is limited to £50 million, will fall far short of the additional costs which arise from bringing forward by several years a capital expenditure of at least £886 million. These additional costs are and will be reflected in the Bulk Supply Tariff, raising the cost to electricity users. We note that the same concern for keeping plant suppliers in work with a view to a future programme is a factor in ordering Heysham II 'in advance of need'.

12. It is not for us to express any view about the justification of the policies mentioned in paragraphs 9, 10 and 11, and we must not be understood to be doing so. We simply conclude from the foregoing that the Board's procurement costs could have been lower. This arises not from lack of efficiency in use of its existing resources, but from concern on its own or the Government's part for the interests of major suppliers. In these circumstances we do not conclude that in these respects the Board has been pursuing a course of conduct which operates against the public interest.

13. We find that the CEGB's management of plant maintenance is generally efficient and that the effect of its programmes for plant maintenance has been to increase plant availability, although we have made a few recommendations for improvement.

14. The fifth matter which we are particularly called upon to examine is the planning and appraisal of new investment, and the Board's ability to carry out its proposals for such investment within the cost and the time estimated. Under the first part of this heading, while we find that the Board's demand forecasting has improved, we consider that there are serious weaknesses in its investment appraisal. In particular a large programme of investment in nuclear power stations, which would greatly increase the capital employed for a given level of output, is proposed on the basis of investment appraisals which are seriously defective and liable to mislead. We conclude

[1] The prices per kilowatt on a common price basis (March 1980) and the dates of order were: Grain (1970) £316; Ince (1972) £425; Littlebrook D (1973) £273; Drax completion (1978) £443.

that the Board's course of conduct in this regard operates against the public interest. Our recommendations for improvement are set out in Chapter 5.

15. The construction of power stations still takes an inordinate time. This has a substantial effect on costs in terms of interest charges, the tying up of specialist manpower, and the retention in use of less economic plant which the new stations are intended to replace. The Board has been wrestling for years with the many problems described in Chapter 12. To the problems which have existed for many years must now be added those which spring from the deteriorating economic climate, such as the temptation to spin out work in order to prolong employment. However, productivity has improved at Grain and Ince albeit from a low level; and Drax completion is on schedule although still at an early stage. Conditions of employment and practices on sites are largely affected by agreements between trade unions and employers' associations which are outside the Board's direct control; but it is taking such steps as are in its power to help to solve the problems of industrial relations in site construction. We think the Board should be encouraged in these efforts. In view of these recent developments we do not find that in this respect the Board is pursuing a course of conduct which operates against the public interest.

16. Although in reaching our overall finding we have been critical of the Board in certain respects, we wish also to record that in the course of our investigation we were impressed with the evident ability and dedication to their work of many of those whom we met. They take a justifiable pride in the technical efficiency and security of the Board's system; and they are fully conscious of the need to supply electricity at the lowest cost obtainable with the existing system. We hope that our recommendations represent a constructive attempt to assist the Board in its task, and that a programme for their implementation will be devised as a matter of urgency.

17. However, we have to stress that, even if our recommendations are fully implemented they offer no early prospect of comfort to the CEGB's customers by way of real price reductions, especially while all fuels are becoming dearer. In this connection, we note that even on the basis of its own latest forecasts, which we believe in some respects to be optimistic, the Board expects the cost of production of electricity to rise in real terms over the next 15 years by 0·77 p/kWh (28 per cent). The proposed investment in nuclear power is not expected to halt the rise in real costs until the late 90s. Since a substantial element of the increased costs up to that time relate to the capital charges of the investment programme itself, this serves to underline the overwhelming importance of the need for the Board to improve its investment appraisal.

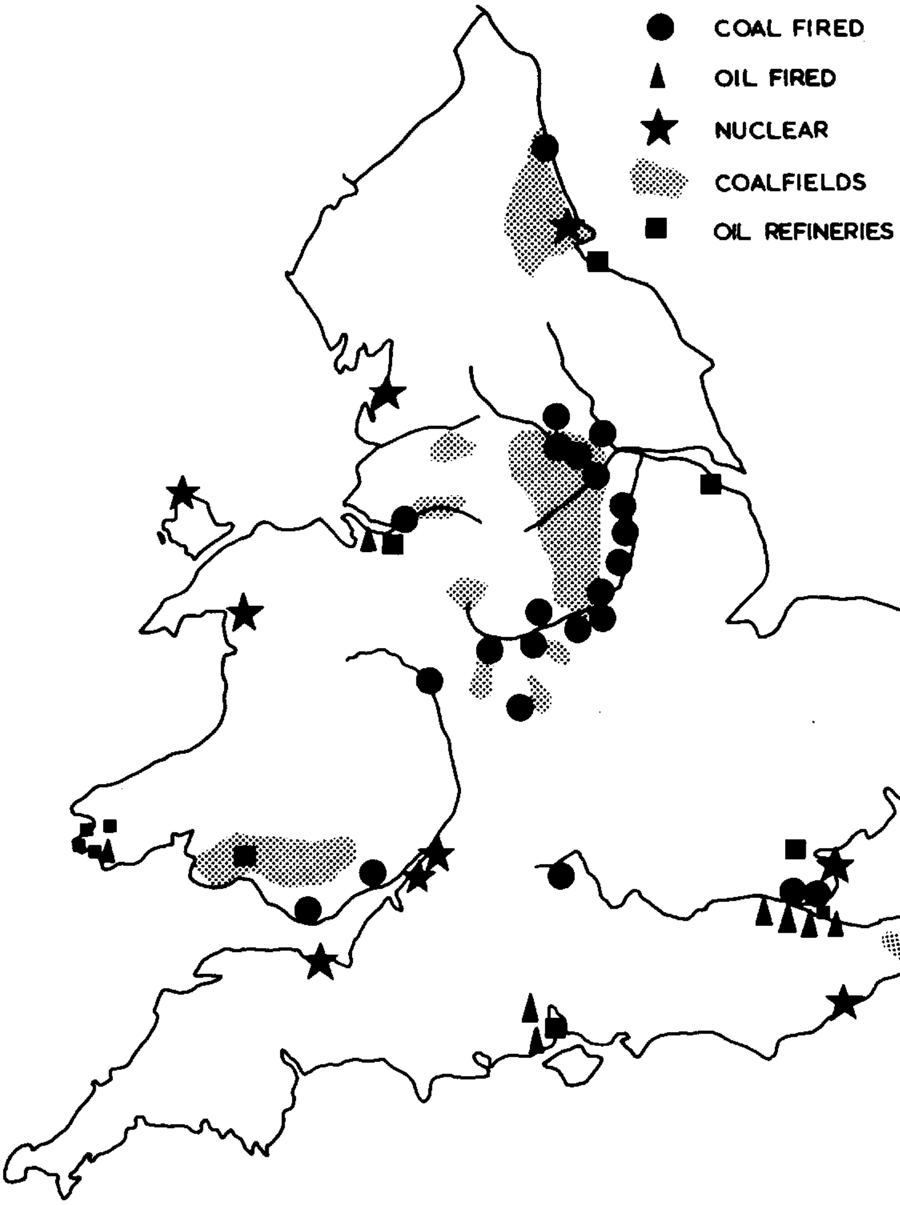
J G Le Quesne *(Chairman)*
H L G Gibson
H Holman Hunt
F E Jones
T P Lyons
C M Miles

J Gill *(Secretary)*
12 February 1981

APPENDIX 1

(Referred to in paragraph 2.5)

Major Power Stations Showing Relationship to Fuel Sources

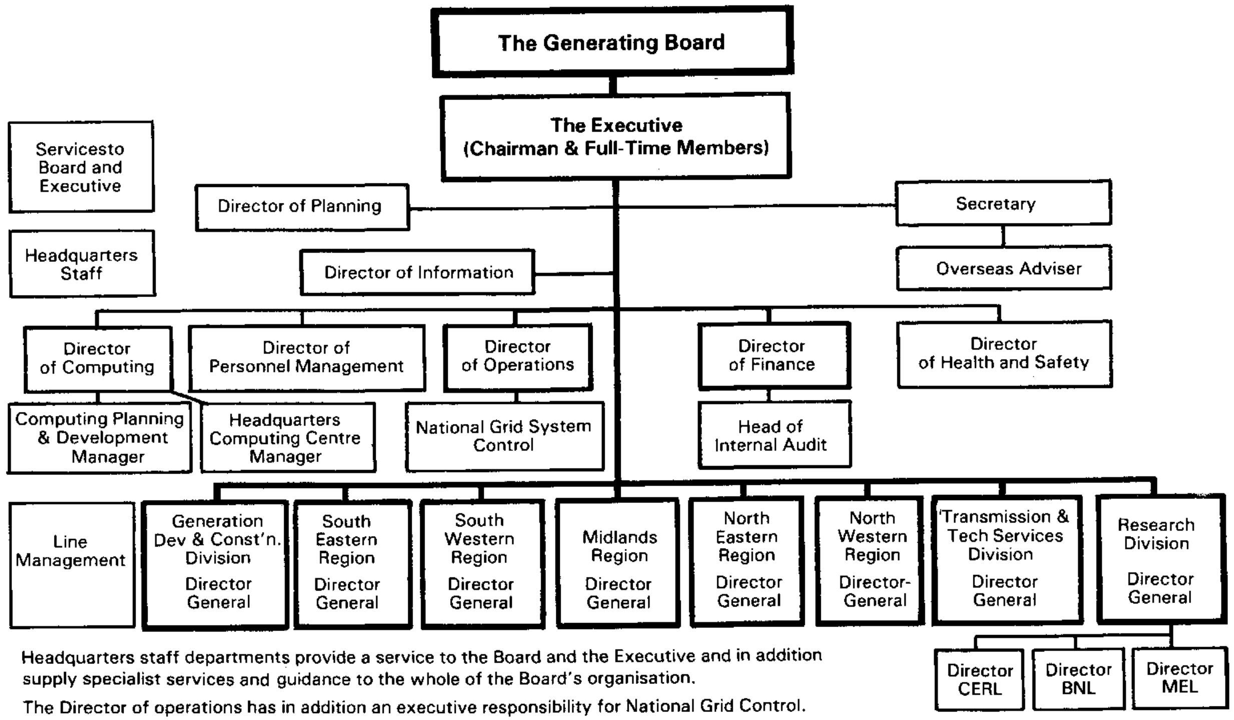


Source: The CEGB

APPENDIX 2

(Referred to in paragraph 2.27)

CEGB ORGANISATION



Headquarters staff departments provide a service to the Board and the Executive and in addition supply specialist services and guidance to the whole of the Board's organisation.

The Director of operations has in addition an executive responsibility for National Grid Control.

Source: The CEGB

Appendix 3

(Referred to in paragraph 3.9)

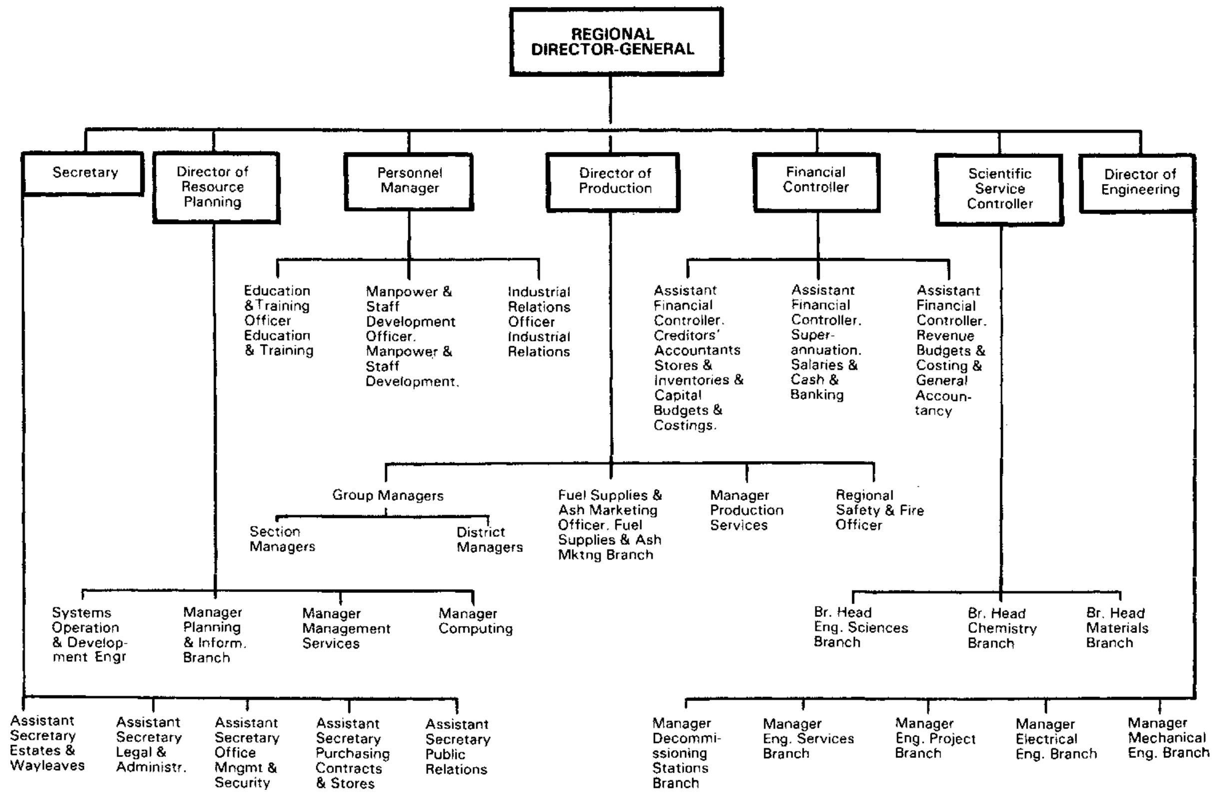
Central Electricity Generating Board
Estimated result for 1980–81 and forecast results for 1981–82 and 1982–83

	1980–81 (Estimated)		1981–82 (Forecast)		1982–83 (Forecast)	
CCA basis	*£m*	*p/kWh*	*£m*	*p/kWh*	*£m*	*p/kWh*
Average net CCA assets, excl capital work in progress	16,900	7·9679	18,900	8·8277	21,300	9·8611
	TWh		*TWh*		*TWh*	
TWh so	217·0		219·0		221·0	
Transmission loss @ 2·3%	(4·9)		(4·9)		(5·0)	
TWh sold	212·1		214·1		216·0	
	£m		*£m*		*£m*	
Sales	5·700	2·6874	6·716	3·1368	7·606	3·5213
Total costs	6,000	2·8289	6·898	3·2218	7·786	3·6046
Less: Interest	(450)	(0·2122)	(470)	(0·2195)	(515)	(0·2384)
Total costs excl interest	5,550	2·6167	6·428	3·0023	7·271	3·3662
Profit before interest	150	0·0707	288	0·1345	335	0·1551
Less: Interest	(450)	(0·2122)	(470)	(0·2195)	(515)	(0·2384)
Profit/(Loss) after interest	(300)	(0·1415)	(182)	(0·0850)	(180)	(0·0833)
Financial target @ 1·8% of net assets as above	304	0·1434	340	0·1589	383	0·1775
Less: Profit before interest – as above	(150)	(0·0707)	(288)	(0·1345)	(335)	(0·1551)
Shortfall below target	154	0·0727	52	0·0244	48	0·0224
				%		%
Nominal % increase/(decrease) over figure for previous year – p/kWh						
Average charge for electricity sold				16·7		12·3
Total costs excl interest				14·7		12·1
Total costs incl interest				13·9		11·9
Profit before interest				90·2		15·3
Loss after interest				(39·9)		(2·0)

Source: The CEGB

APPENDIX 4 *(Referred to in paragraph 3.30)*

Central Electricity Generating Board—Midlands Region



Source: The CEGB

APPENDIX 5

(Referred to in paragraph 3.36)

Summary of the Performance Against Budgets of the South Eastern and Midlands Regions for the Years 1975–76 to 1979–80

	1975–76		*1976–77*		*1977–78*		*1978–79*		*1979–80*	
	SER	*MR*	*SER*	*MR*	*SER*	*MR*	*SER*	*MR*	*SER*	*MR*
1. *Fuel*										
Flexed Budget	286·7	437·2	247·2	546·2	300·6	621·5	294·8	716·2	357·7	911·3
Actual	285·5	421·4	245·5	543·2	301·9	621·8	304·1	716·0	366·6	901·4
% Variation	(–)0·4	(–)3·6	(–)0·7	(–)0·5	0·4	—	3·2	—	2·5	(–)1·1
2. *Purchases of Electricity*										
Budget	—	—	—	—	—	—	—	0·3	—	—
Actual	—	—	—	—	—	—	—	—	—	—
% Variation	—	—	—	—	—	—	—	(–)100·0	—	—
3. *Irradiated Fuel Processing*										
Budget	3·9	—	6·6	—	13·2	—	16·7	—	19·0	—
Actual	3·9	—	7·5	—	11·2	—	14·3	—	11·9	—
% Variation	—	—	13·6	—	(–)15·2	—	(–)14·4	—	(–)37·4	—
4. *Salaries*										
Budget	61·9	56·5	70·8	60·5	76·6	64·9	93·6	77·8	115·6	93·6
Actual	64·3	56·4	70·7	59·7	76·5	64·6	93·9	76·6	114·6	91·1
% Variation	3·9	(–)0·2	(–)0·1	(–)1·3	(–)0·1	(–)0·5	0·3	(–)1·5	(–)0·9	(–)2·7
5. *Other Costs*										
Budget	33·2	47·0	42·1	67·6	55·7	79·3	67·4	98·4	80·5	116·0
Actual	38·7	54·8	43·9	65·0	52·7	79·7	68·5	98·5	80·6	117·4
% Variation	16·6	16·6	4·3	(–)3·8	(–)5·4	0·5	1·6	0·1	0·1	1·2
6. *Miscellaneous Income*										
Budget	(–)3·0	(–)6·9	(–)2·6	(–)8·6	(–)4·9	(–)8·5	(–)5·3	(–)9·5	(–)6·4	(–)11·1
Actual	(–)2·4	(–)7·8	(–)4·9	(–)8·7	(–)5·6	(–)9·6	(–)5·7	(–)10·8	(–)7·1	(–)13·0
% Variation	20·0	13·0	88·5	1·2	14·3	12·9	7·5	13·7	10·9	17·1
7. *Net Expenditure*										
Budget	382·7	533·8	364·1	665·7	441·2	757·2	467·2	883·2	566·4	1109·8
Actual	390·0	524·8	362·7	659·2	436·7	756·5	475·1	880·3	566·6	1096·9
% Variation	1·9	(–)1·7	(–)0·4	(–)1·0	(–)1·0	(–)0·1	1·7	(–)0·3	—	(–)1·2

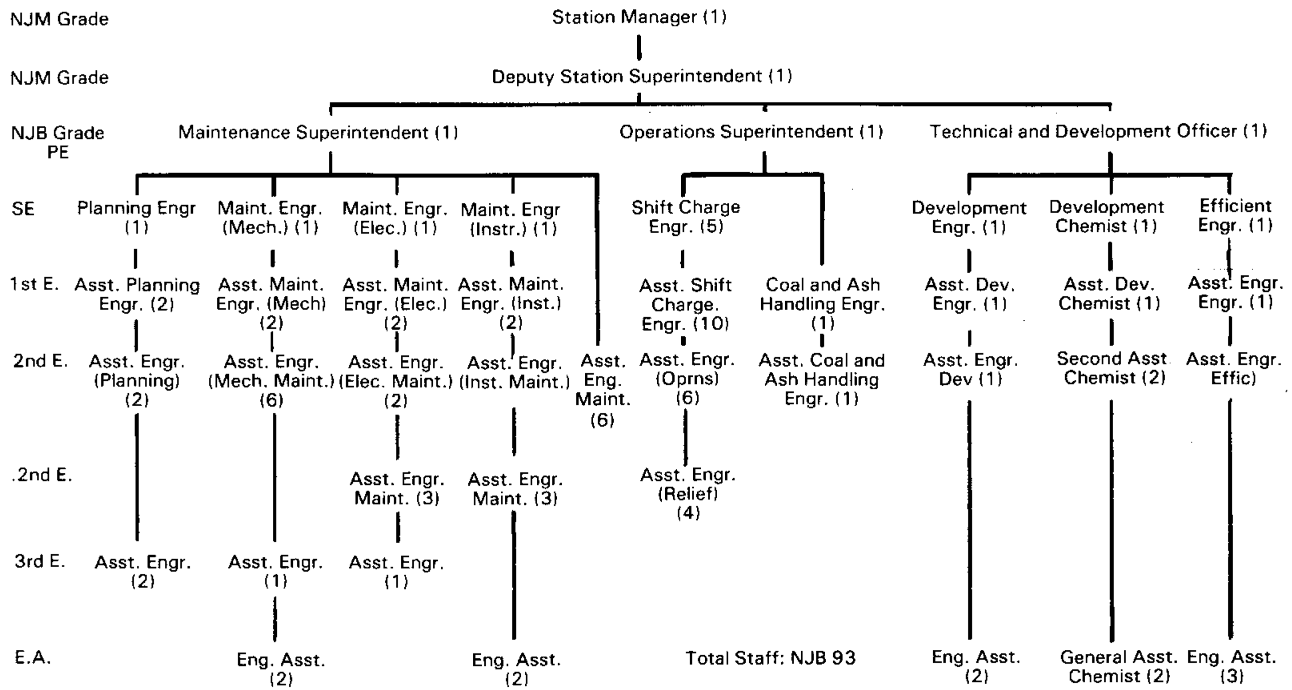
Source: The CEGB

APPENDIX 6

(Referred to in paragraph 3.37)

Central Electricity Generating Board

Midlands Region Ratcliffe-on-Soar Power Station
NJB Staff Organisation 1980–81



Source: The CEGB

APPENDIX 7 *(Referred to in paragraph 3.37)*

Central Electricity Generating Board – Midlands Region

STATEMENT OF RESOURCE MANAGEMENT **POWER STATION** Review Period . . . .

		ACTUAL RESULTS this period (1)	PERIOD 1st APRIL TO DATE Budget (2)	Actual (3)	Variance (4)	ANNUAL BUDGET/OUT-TURN FORECAST Budget (5)	Forecast (6)	Variance (7)
(1) Declared Net Capability	MW							
(2) Units Supplied	GWh							
(3) Works Units	%							
(4) Thermal Efficiency	%							
(5) S.T.E.P. Factor	%							
(6) Overhaul Programme MW. wks./Saving (Cost)	£000				/			
(7) R.C.A. Saving (Cost)	£000							/
(8) Capability Available % (6 + 7)/Saving (Cost)	£000				/			/
(9) Cost of Fuel Burnt	£000							
(10) Average	p/Gj							
(11) SALARIES – NJM/NJB	£000							
(12) – NJC	£000							
(13) – NJIC	£000							
(14) – TOTAL SALARIES	£000							
(15) MANPOWER – NJM/NJB	Manyears/In Post	/	/	/	/	/	/	/
(16) – NJC	Manyears/In Post	/	/	/	/	/	/	/
(17) – NJIC	Manyears/In Post	/	/	/	/	/	/	/
(18) OVERTIME PAID (incl. above) – NJB	£000							
(19) Cost of Callouts incl.	£000	( )		( )				
(20) – NJC	£000							
(21) NJIC	£000							
(22) Total Overtime Paid	£000							
(23) NJIC – Overtime hrs./Normal hrs.	%							
(24) MAJOR JOBS	£000							
(a)								
(b)								
(c)								
(d)								
(25) TOTAL MAJOR JOBS								
(26) TOTAL OTHER EXPENDITURE								
(27) TOTAL OTHER RESOURCES (25 + 26) Comprising								
(28) Stores								
(29) Other Materials and Charges								
(30) Contracts								
(31) TOTAL RESOURCE/STATION COST (9 + 14 + 27)								
SITE/STATION COST SUMMARY	£000						Value of stores held at period ends . . .	
(32) Cost of Fuel Burnt								
(33) Operation Cost								
(34) Repairs and Maintenance Cost								
(35) TOTAL WORKS COST								
(36) (Works Cost p/k Wh Supplied)		( )	( )	( )	( )	( )		
(37) Site Overheads								
(38) Other Costs								
(39) TOTAL SITE COST								
(40) Add Charges to other Budget Centres								
(41) Income Netted above								
(42) Less Charges from other Budget Centres							Target budget 31 March	
(43) TOTAL RESOURCE COST								

Source: The CEGB

APPENDIX 7 (Contd.)

Central Electricity Generating Board—Midlands Region

Production Department Monthly Revenue Expenditure Statement

Department
Group
Station
District

Year 197 /197

Period........................
Date of Issue..................

£000

	EXPENDITURE	4M	5M	6M	7M	8M	9M	10M	11M	12M	1M	2M	3M	REVISED BUDGET	ORIGINAL BUDGET
MAJOR JOBS	BUDGET PROGRAMME														
	TOTAL COMMITMENT TO DATE (to be invoiced this financial year)														
	ESTIMATED VALUE OF WORK DONE														
OTHER EXPENSES	TOTAL COMMITMENT TO DATE (to be invoiced this financial year)														
	ESTIMATED COSTS TO DATE														
													TOTALS		

REMARKS:

Source: The CEGB

APPENDIX 8

(Referred to in paragraph 3.40)

Generation Development and Construction Division – Outturn Against Budget

£'000

	1976–77		1977–78		1978–79		1979–80	
	Approved Supplemented Budget	*Outturn*	*Approved Supplemented Budget*	*Outturn*	*Approved Supplemented Budget*	*Outturn*	*Approved Supplemented Budget*	*Outturn*
Salaries	12,933	12,796	13,579	13,351	15,366	15,311	19,280	19,581
Travel and subsistence	—	—	—	—	1,144	1,062	1,188	1,125
Materials, services etc	11,955	10,706	13,211	11,214	15,538	12,859	19,574	19,502
Rents, rates, insurance	235	163	212	164	217	185	234	222
Total Budget Centre Resources	25,123	23,665	27,002	24,729	32,265	29,417	40,276	40,430
Add 'in house' etc services received	4,202	4,194	4,145	3,636	4,506	4,617	5,277	5,188
Gross expenditure	29,325	27,859	31,147	28,365	36,771	34,034	45,553	45,618
Less 'in house' etc services provided	120	127	100	260	257	223	247	301
Income	19	243	487	314	587	601	534	651
Net expenditure	29,186	27,489	30,560	27,791	35,927	33,210	44,772	44,666
Charged to Capital		18,889		17,907		22,358		27,947
Revenue		7,747		9,235		9,935		15,770
Other Accounts		853		649		917		949
Employees in post at year-end		2,006		1,918		1,930		2,002

Source: The CEGB

Notes:
1. The 1975–76 budgeted and outturn figures for 'in house' etc services received are stated net of cost of services provided.
2. Amounts charged to other accounts represent 'in house' profit/overhead.
3. Prior to being shown separately from 1978–79 onwards travel and subsistence expenditure was included under materials, services etc.

APPENDIX 9

(Referred to in paragraph 3.41)

Headquarters Departments – Outturn Against Budget

£'000

	1976–77 Approved Supplemented Budget	1976–77 Outturn	1977–78 Approved Supplemented Budget	1977–78 Outturn	1978–79 Approved Supplemented Budget	1978–79 Outturn	1979–80 Approved Supplemented Budget	1979–80 Outturn
Salaries	15,732	15,353	17,299	16,487	19,716	19,421	25,199	23,737
Travel and subsistence	—	—	—	—	1,324	1,269	1,578	1,586
Materials, services etc	11,566	10,521	15,180	12,895	16,175	13,343	19,474	15,952
Rents, rates, insurance	11,471	11,299	11,450	11,862	11,827	11,434	12,952	13,011
Department's own costs	38,769	37,173	43,929	41,244	49,042	45,467	59,203	54,286
'In house' etc services received	2,551	2,158	3,132	2,331	3,200	2,953	3,704	3,357
Gross expenditure	41,320	39,331	47,061	43,575	52,242	48,420	62,907	57,643
'In house' etc services provided	10,569	10,018	11,536	10,433	12,754	12,605	15,155	14,572
Income	2,657	3,326	3,785	4,136	4,969	4,583	5,169	5,332
Net expenditure	28,094	25,987	31,740	29,006	34,519	31,232	42,583	37,739
Employees in post at year-end		2,351		2,383		2,486		2,477

Source: The CEGB

APPENDIX 10

(Referred to in paragraph 3.41)

HQ Departments Budget Against Outturn 1979–80

£'000

Department	*Approved Supplemented budget*	*Outturn*	*Variances*
Board members' offices	252	263	11
Computing Centre*	(1,011)	(1,059)	(48)
Computer Planning and Development	1,454	1,313	(141)
Engineering Services*	(1,398)	(1,254)	144
Finance	2,626	2,010	(616)
Health and Safety	2,193	2,240	47
Operations	6,701	5,738	(963)
Personnel	4,994	4,187	(807)
Planning	7,024	5,020	(2,004)
Press Office	566	605	39
Secretary's	19,182	18,676	(506)
	42,583	37,739	(4,844)

Source: The CEGB

* Computing Centre and Engineering Services budget centres both anticipate operating surpluses because income arising from charging for the provision of in house and external services is expected to exceed the costs of those departments.

APPENDIX 11

(Referred to in paragraph 3.42)

Summary of Total Board Performance against Budgets for the years 1975–76 to 1979–80

£'000

	1975–76 Total Board	*1976–77 Total Board*	*1977–78 Total Board*	*1978–79 Total Board*	*1979–80 Total Board*
1. *Fuel*					
Flexed budget	1,494·9	1,696·2	2,000·2	2,236·4	2,728·4
Actual	1,466·4	1,687·7	2,012·2	2,249·6	2,723·1
% Variation	(−)1·9	(−)0·5	0·6	0·6	(−)0·2
2. *Purchases of electricity*					
Budget	10·3	13·4	15·9	22·6	26·4
Actual	12·2	12·7	17·2	20·2	24·1
% Variation	18·4	(−)5·2	8·2	(−)10·6	(−)8·7
3. *Irradiated Fuel Processing*					
Budget	10·0	23·6	45·8	61·5	75·0
Actual	10·1	24·2	40·5	52·3	60·6
% Variation	1·0	2·5	(−)11·6	(−)15·0	(−)19·2
4. *Salaries*					
Budget	288·5	318·4	342·5	411·0	506·6
Actual	295·2	316·5	339·1	412·8	500·9
% Variation	2·3	(−)0·6	(−)1·0	0·4	(−)1·1
5. *Other costs*					
Budget	230·8	296·8	332·9	394·7	457·2
Actual	249·2	287·1	326·5	391·9	459·3
% Variation	8·0	(−)3·3	(−)1·9	(−)0·7	0·5
6. *Miscellaneous income*					
Budget	(−)17·4	(−)21·7	(−)27·7	(−)31·6	(−)37·3
Actual	(−)18·4	(−)26·5	(−)30·9	(−)35·0	(−)41·4
% Variation	5·7	22·1	11·6	10·8	11·0
7. *Net expenditure*					
Budget	2,017·1	2,326·7	2,709·6	3,094·6	3,756·3
Actual	2,014·7	2,301·7	2,704·6	3,091·8	3,726·6
% Variation	(−)0·1	(−)1·1	(−)0·2	(−)0·1	(−)0·8

Source: The CEGB

APPENDIX 12

(Referred to in paragraph 4.33)

The Bulk Supply Tariff

The calculation of marginal costs and the setting of the BST structure

1. As paragraph 4.31 explains, the CEGB has told us that it employs the principle of long run marginal cost pricing to set the structure of the BST. To apply this pricing policy successfully the Board must calculate long run marginal costs correctly, and then set the structure of the BST in a way which appropriately reflects the calculation. We therefore examined the Board's calculation of long run marginal costs and the extent to which the structure of the BST corresponds to these calculations.

2. The Board has identified three main types of expenditure:

(i) expenditure on the provision of supply points as agreed with Area Boards;

(ii) expenditure on the provision of sufficient capacity (both generating plant and transmission lines) so that demand can be met;

(iii) operating expenditures associated with the provision of electricity to meet demand.

It has therefore established a tariff with three types of charge:

the Service Charge (associated with (i));
Demand Charges (associated with (ii)); and
Energy Charges (associated with (iii)).

3. In the case of the *Service Charge*, the CEGB agrees with each Area Board the plant and equipment required at its bulk supply points. The charge for each supply point is the sum of its related capital and maintenance charges.

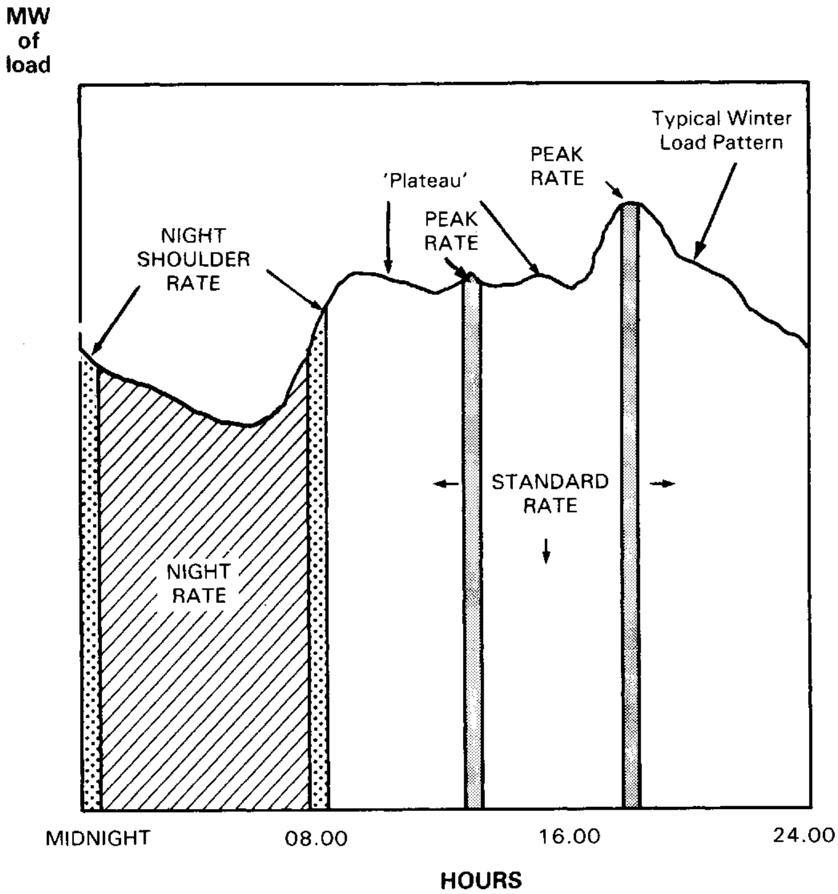
Demand and Energy Charges

4. The Demand and Energy Charges relate to the way the CEGB optimises its operations. The Board has established operating procedures (the merit order principle which Chapter 6 explains) which imply that the marginal costs of operating the system increase as load increases. Figure 1 shows a typical winter load curve, and it is noteworthy that such a pattern will give marginal costs in the afternoon which are higher than at night. Further, if enough plant must be available to meet the peak, then some units will be utilised much less than others; the CEGB's investment appraisal suggests that this implies that different types of plant should be held, depending on the utilisation required. Thus the marginal costs of supply capacity to meet a demand charge will be different if the change shifts the whole load curve up or down, or merely changes its shape so that it becomes smoother or more peaked.

5. Therefore, to set the rates for the Demand Charges, the CEGB distinguishes between the capacity required to meet the extreme peak of the year and that required for the winter 'plateau' (the almost even level of load each day between 8.00 am and 4.00 pm as shown in Figure 1). On this basis it calculates what it believes are the relevant marginal costs, using the following arguments.

FIGURE 1

Typical load curve and 1980–81 Bulk Supply Tariff unit rates



Source: The CEGB

(i) BASIC DEMAND

6. The capacity which meets 'basic demand' (that part of the load curve which forms the 'plateau') is described as 'basic' capacity. If basic demand shifts up for a sufficient period to convince the Board that the shift is not a temporary aberration then it will consider that it requires new plant. A corresponding shift downwards will, again if not a temporary aberration, convince the CEGB that it can defer the order of new plant intended to replace stations at the end of their useful life. New plant the order for which is to be advanced or deferred will be of the most modern type with the highest efficiency, and may be either nuclear or coal-fired, but the CEGB bases its calculation of the marginal costs of basic capacity on the costs of new coal-fired plant. If the Board used its basic estimate of 'typical' new nuclear plant then its estimate of this marginal cost would be much less (indeed negative).

However, the Board argues that in the long run it will be able to alter the type of plant on the system to produce a mix close to the optimum, that as it does so the cost of nuclear plant will approach that of new coal-fired plant now, and hence that it is correctly assessing long-run marginal costs.

7. Net Effective Cost (see paragraph 5.12) is the Board's estimate of the effect of an investment in new plant on the Board's total system costs over the plant's lifetime, and is therefore used to calculate the marginal cost of capacity. The NEC is calculated on the assumption of a given demand, and in the case where demand increases is actually too low by a small amount. This is because it credits the new plant with a system saving for completely replacing old units in operation, whereas if demand were to increase substantially then the Board would need both to invest and to retain old plant. Nonetheless the Board considers NEC to be a close approximation, because the extra system savings can be shown to depend upon the rate at which operating cost per kWh rises at the bottom of the merit order, which the Board describes as relatively slow. In order to calculate the full marginal cost of basic capacity, the Board adds allowances to the basic estimate of the NEC of new coal-fired plant to account for transmission costs and the need to keep a planning margin. Table 1 shows the calculation of this marginal cost used in the derivation of the 1980–81 BST. The rate for Basic Capacity was set at £30 per kW in the 1980–81 BST.

(ii) THE MARGINAL COST OF PEAKING CAPACITY

8. The difference between the system peak in ACS conditions and the 'plateau' of basic winter-time demand is described as the amount of 'peaking' demand. If this peaking demand rises (and the rise is not judged temporary) then the Board will consider whether to adjust capacity to meet this rise. At present it has more than sufficient plant low in the merit order and hence a rise would have to be very large for investment requirements to alter. The CEGB estimates that as the system approaches an optimal plant mix, which it is expected to do in the long run, then any increment of peaking demand would be most economically met by the installation of gas turbine plant. The relevant basic NEC, together with appropriate allowances, is the Board's estimate of the marginal cost of such an increment to demand.

9. If, however, peaking demand were to fall (and the change was not thought temporary), then the CEGB would find it economic to de-commission older plant which was previously only used to meet this demand, a small rise in peaking demand can be met by retention of such units. Thus the Board considers this cost or saving relevant to calculating the marginal cost of peaking capacity, although retention of old plant may not be an option in the longer run. Estimates of the typical annual saving from such de-commissioning including the planning margin and associated transmission are in the range of £5 to £10 per kW for the current year (as compared with a range of £5 to £15 for the early 1990s mentioned in paragraph 5.129). Hence in its calculation of the marginal cost of meeting peaking demand for the 1980–81 BST the Board faced the difficulty that it had estimated a decrement or an increment in the medium term as saving or costing much less (£5 to £10 per kW) than an increment in the long run would cost (£30 per kW, after correction

to ensure that revenue would not exceed the estimated requirements of the financial target). It therefore compromised on an 'average' of £14 per kW to represent the marginal cost of the capacity required to meet peaking demand. Table 1 shows the calculation of the marginal cost of peaking capacity:

TABLE 1 **The CEGB's calculation of the marginal cost of new capacity for the 1980–81 BST**

	Coal (considered to be capacity to meet basic demand) £/kW	*GT* (considered to be capacity to meet the peaking demand) £/kW	Retaining old plant £/kW
Basic estimate of net effective cost of new plant (including associated transmission)	24	25	
Allowance for planning margin	+6	+7	
Allowance for transmission losses	+1	+1	
	31	33	5–10
Less correction to bring total revenue down to Government financial target*	1	3	
Estimate used for 1980–81 BST	30	30	10

Source: The CEGB

* As explained in paragraph 4.31.

ENERGY CHARGES

10. To set the Energy Charges, estimates are required of the marginal cost of operating the system to supply electricity. These operating costs vary with the level of load because the merit order principle is employed by the operators, and the CEGB therefore divides the day into eight periods (as shown in Figure 1 above), during which the marginal costs of operating are significantly and persistently different, and sets four different rates to cover the eight periods. The calculation of these marginal costs is done by estimating which plant will be the last to be brought on to the system to meet the average level of load in the period; the marginal cost is taken to be all the small output-related operating costs of this plant—the main component is fuel cost for which a forecast of prices over the coming year is made, but the costs include ash handling, boiler cleaning and use-related maintenance. As fossil plant has to be heated up before its output can be brought on to the system, and hence incurs costs before producing output, the calculation includes an allowance for this expenditure. Table 2 gives the calculations made for the 1980–81 BST.

11. The CEGB does not distinguish between marginal costs of summer and winter operation, because it finds that the marginal plant on the system has similar costs at all times of the year. This results from the policy of arranging the outages for maintenance of high merit order plant to occur in summer. The Board has considered setting more time-of-day rates, but argues that: 'an over-complex structure would require metering on consumers' premises of an expensive kind and could only be justified economically in rare cases'.

TABLE 2 **The CEGB's calculation of the marginal costs of operation for 1980–81 BST and BST rates**

Period	*Estimated Marginal Costs* Price* (pence per kWh)	*BST rates including 1980 estimate of fuel cost adjustment*	*Estimated BST rates as a proportion of marginal costs*
Peak	4·97	4·33	87%
Standard	2·70	2·41	89%
Night	1·32	1·34	102%
Shoulder	2·23	2·02	91%

Source: The CEGB

* Assuming national fossil fuel price of 4,250 pence per tonne (ie the forecast for 1980–81 made in March 1980 when the tariff was set).

These figures are based on estimates of output related works costs (other than fuel) at the marginal plant of:

Period	*Costs* p/kWh
Peak	0·5
Standard	0·3
Night	−0·05 (ie the CEGB saves).

ADJUSTMENT FOR FINANCIAL TARGET

12. Paragraph 4.31 explained that the principle of marginal cost pricing was applied only in so far as it was consistent with the Board's financial target. The Board told us that 'if the Tariff rates have to differ from the marginal rates the brunt is borne by the less elastic features of the tariff, in particular the "basic capacity charge" and the "standard" kWh rate'. It appears that the Board applies this principle in a rough and ready way, since it made no reduction in the more elastic peaking capacity charge and in the night energy rate. However, the adjustment it made to the basic capacity charge was £1 in £30 (ie about 3 per cent) whereas it adjusted Energy Charges by just over 10 per cent.

DEMAND CHARGING CALCULATIONS

13. To calculate the Demand Charges the CEGB has had to develop a formula to enable it to attribute a particular proportion of capacity to each Area Board. Any such formula must be formally equitable, but also must not be such as to allow any Area Board to organise its pattern of demand in such a way that it is recorded as having used CEGB's system much less than it actually did. The Board has developed a formula for peaking capacity which it believes satisfactory, and this is set out in Appendix 2 of its 1979–80 Annual Report. The essential feature is that demand is recorded on three days: the day in the year when demand is at its peak and two other days which must be more than 10 days before or after the day of maximum system demand. The Board measures each Area Board's take at the peak half-hour of each of the three days, and thereby derives the average for each Area Board, taking this to be the Area Board's share of capacity.

14. The CEGB calculates the shares of basic capacity by examining how much each Area Board has taken when demand was between 85 per cent and 86 per cent of system peak load. It identifies all the half hour periods during the past year when load was in this range, and each Area Board's take for each of these periods is then found. The average take by each Area Board during these periods is calculated, and this is assessed to be its share of basic load. An Area Board's peaking load is then the difference between the basic load it took, and its share of the peak. However, the CEGB adjusts the Area Board's peaking charges to give the due credits for Load Management.

15. The use of this formula for Demand Charging creates some uncertainty for all concerned, because no Area Board can be sure to within a few per cent what basic or peaking capacity it is assessed to have taken until after the winter peak period, ie well into the last quarter of the financial year; similarly the CEGB cannot know to any greater degree of accuracy. The CEGB therefore sets Maximum and Minimum Charges for Basic Capacity at the beginning of the year on the basis of forecast take, and Area Boards are only charged according to the BST formula if the result lies within the range. Otherwise the Maximum or Minimum charge as appropriate is levied. Appendix 2 of the CEGB's 1979–80 Annual Report gives the 1980–81 Maxima and Minima.

THE FUEL COST ADJUSTMENT

16. The BST provides for adjustments to the Energy Charges during the year to reflect any difference between the CEGB's forecast and monthly outturn fossil fuel prices, calculated on a replacement cost basis. The expression 'fuel cost adjustment' is therefore not strictly accurate, because if actual costs differ from the forecast level, leaving fuel prices unaffected (for example as a result of a change in thermal efficiency), then the change is not reflected in the tariff. It is noteworthy that not only changes in fuel prices, but also changes in system operation can affect the average fossil fuel price. For example, a different pattern of plant availability during the year may alter the quantity and mix of fuels burnt, and hence the average price. Area Boards used to include a similar mechanism in their tariffs, but have abandoned this practice for quarterly billed consumers on the recommendation of the Price Commission.

APPENDIX 13

(referred to in paragraph 4.58)

Derivation of the Planning Margin from the Generation Security Standard

The probability distribution of surplus generation capacity

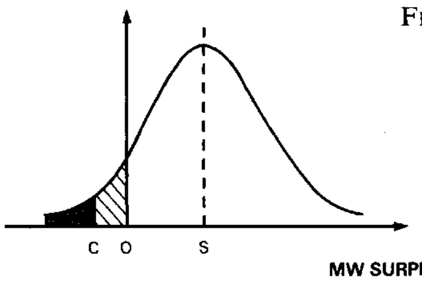
1. Paragraph 4.45 gives the generation security standard and paragraph 4.57 gives the estimates from which the Board calculates the planning margin required. These estimates, together with a small statistical allowance for the probability of help from Scotland, produce a combined probability distribution (the shape of which is normal, because the CEGB assumes that the distribution of each of the three elements, availability, weather-related demand and demand in ACS conditions, is normal).

2. The standard deviation in forecast peak demand because of weather variation is calculated by analysis of the relationship between demand and weather in the past. Similar analysis is undertaken to establish the spread of plant breakdown over past years; the Board then assesses, by judgment, the likely extent of error in its forecast of average winter peak plant availability in the seventh year ahead, and combines the past analysis and judgment of the future (which are taken to be of about equal importance) to obtain an estimate of the standard deviation of forecast availability during the winter peak. The Council determines the standard deviation of forecast peak demand because of forecasting error by judgment; however, as the margin is its responsibility, the Board has considerable influence over the judgment. The forecasting record for the last few years had a standard deviation of 12 per cent (although it is noteworthy that the errors took the form of over-forecasting rather than a random error around the expected mean). The Council judged that future forecasting should be assumed to be better than the past and hence agreed that 9 per cent was appropriate.

3. The Electricity Consumers' Council has suggested to us that because the risk in forecasting is rather more that the central estimate is too high than too low (ie the distribution is skewed), the allowance for forecasting error could be lowered.

4. Figure 1 illustrates the resulting distribution of the probabilities of different surpluses and deficits in available plant in seven years' time at the yearly peak:

FIGURE 1



Distribution of Surplus Generation Capacity at Peak

The extreme left tail of the curve shows the probability of shortage of plant; the probability is lower the larger the shortage. The expected surplus of plant is S, and there is an even chance that the surplus will be greater than this. 0 represents the point at which available plant exactly equals peak demand, ie if available plant is less, frequency or voltage must be reduced. C represents the point at which available plant is 7½ per cent below demand, ie if the number of megawatts of availability plant falls below this then some consumers will have to be cut off. The current security standard states that the probability that voltage and frequency reduction will be necessary at the yearly peak must not be greater than 19 in a 100, which is equivalent to stating that the shaded area to the left of 0 must not be more than 19 per cent of the total area under the curve. Similarly the double shaded area to the left of C must not be more than 4 per cent of the total area under the curve.

5. On present estimates of risk, the net surplus of plant (ie the point S) must be about 8·8 per cent above the expected restricted simultaneous maximum demand (net of external supplies) in average cold spell conditions in seven years' time, to be met by the CEGB capacity. This figure is 47,500 MW in 1987–88 and hence the net surplus in seven years' time must be 8·8 per cent of 47·5 GW which is just over 4,000 MW, equivalent to over two large stations such as Drax and Drax completion. Assuming that average plant availability during the winter peak of the seventh year is 85 per cent, then a 28 per cent gross surplus of capacity must be held to give 8·8 per cent net surplus. This is because 85 per cent of 128 is 108·8.

6. The CEGB has calculated how much the gross planning margin would be affected by changes in the security standard. These calculations are shown in the Table 1 below:

TABLE 1 **The security standard and planning margin**

Security standard		*Resulting planning margin*
Number of winter peaks in 100 when supply would be interrupted	Number of winter peaks in 100 when voltage and/or frequency would be reduced	
3	16	29.5%
4	19	28%
5	21	27%
10	33	23%
16	42	20%

Source: The CEGB

7. These calculations were made in 1977, and used the CEGB's estimates of risk and plant availability,[1] which have not been subsequently altered. They indicate that the Council would have to accept a risk of interruption of more than twice the present level before the margin could be altered significantly.

[1] 'Power Station Planning in England and Wales' by R P Jenkin gives the formulae by which the margin can be derived (delivered in 1978 at the Winter Power Meeting, New York, of the American Institute of Electrical and Electronic Engineers).

8. Thus the calculation of the margin is a matter of technique given estimates of the four elements, but a considerable element of judgment in the derivation of the margin remains. Judgments are made of what should be assumed, seven years ahead, for average winter peak plant availability, load forecasting error and error in the forecast of plant availability, and the shapes of the various probability distributions.

APPENDIX 14

(referred to in paragraph 6.28)

The SYMAN Simulation Suite details

1. Figure 1 shows in outline the data sources and flows necessary for the simulation energy studies by the SYMAN suite. It is estimated that data preparation for this suite requires about ten man-years of effort annually.

Details of input data needed for the three modules

2. MOCAL requires as input:

(*a*) The heat rate of each set.

(*b*) The system marginal fuel cost at each set.

NELS requires as input:

(*a*) The shape and magnitude of the demand curve. This is generated by a further program CURNL which processes historic demand data to estimate daily demand profiles aligned to total integrated energy estimates. The SYMAN program uses seven daily profiles to represent each month period in the review. Weighted factors are used on the profiles to the Saturday, Sunday and weekday profiles to the integrated monthly energy demand.

(*b*) Output capacity of each set.

(*c*) The relationship between load and heat input for each set. The program assumes a combination of two linear functions.

(*d*) The generation level at which sets are synchronised.

(*e*) The rates of loading and deloading of sets.

(*f*) The minimum shutdown duration of each set.

(*g*) Minimum stable generation of each set.

(*h*) The output level at which the coal/oil fuel mix will change on each set.

(*i*) The minimum time interval between synchronising successive sets on each station.

(*j*) The minimum time interval between shutting down of successive sets on each station.

(*k*) Non-availability of sets due to planned outage.

(*l*) The reliability of each set.

(*m*) Transmission constraints.

(*n*) Plant inflexibility.

COFAL requires as input:

(*a*) The on-load and off-load heat required at each station.

(*b*) Fuel stock levels.

(*c*) For each fuel source—availability;
—calorific value;
—source costs.

(*d*) For each transport route source to power station
—mode available;
—cost of each mode.

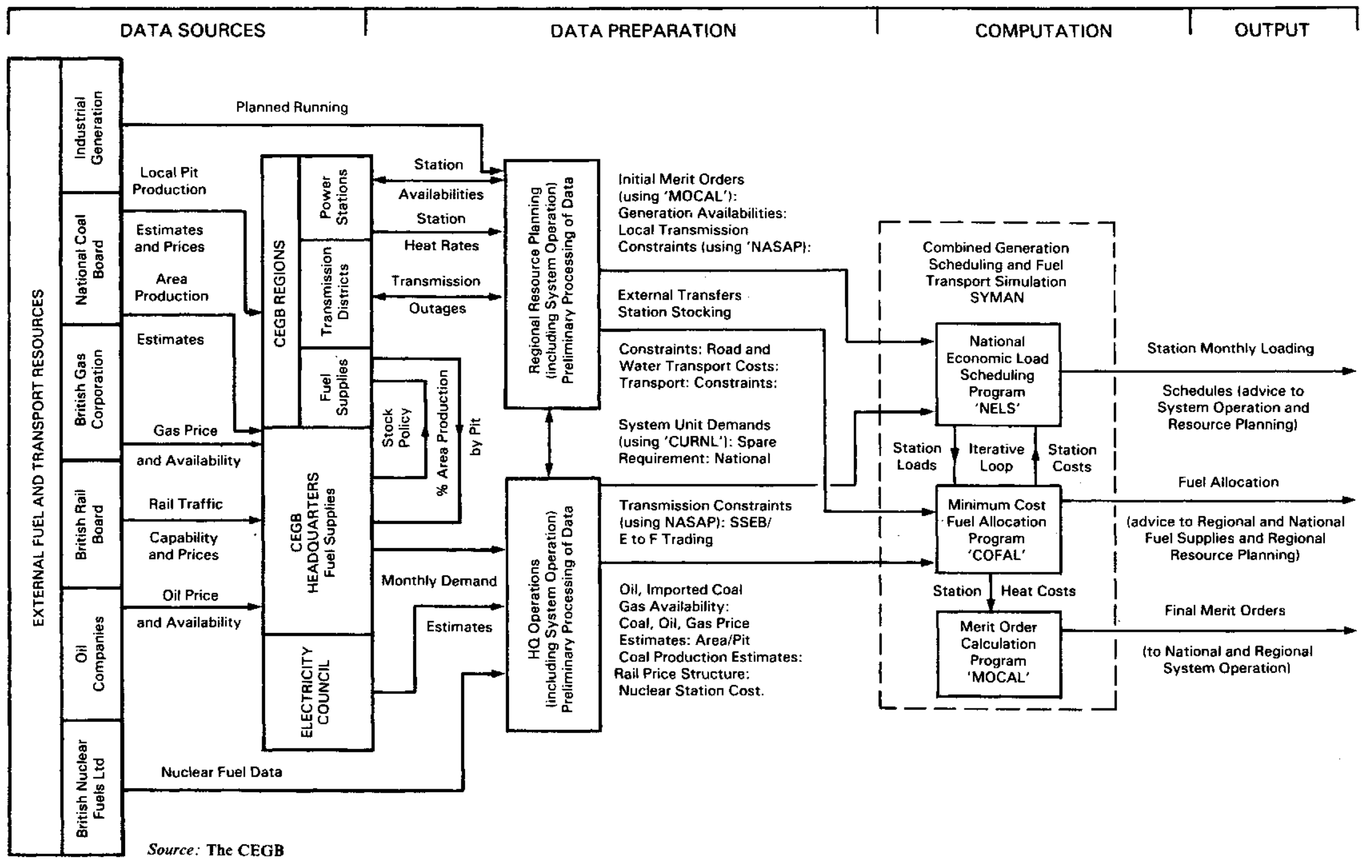
(*e*) The marginal cost of fuel and ash handling at each station.

(*f*) Constraints on fuel quality at each location.

(*g*) Capacity constraints action on each transport mode and route.

APPENDIX 14 (*Contd.*)

FIGURE 1



Source: The CEGB

APPENDIX 15

(Referred to in paragraph 6.55)

Predicting availability and thermal efficiency performance

Availability prediction

1. Availability can be estimated from a knowledge of three components:

$$\begin{aligned} \textit{Availability} = 1 - & \\ = & \left\{ \text{Proportion of total time spent on planned outage} \right\} \\ + & \left\{ \begin{array}{l} \text{Proportion of total time spent on recurrent component} \\ \text{outage} \end{array} \right\} \\ + & \left\{ \begin{array}{l} \text{Proportion of total time spent on non-recurrent com-} \\ \text{ponent outage} \end{array} \right\} \end{aligned}$$

An estimate of each component made, using the following data sources:

(i) Historical records of outages and causes of loss of output recorded both locally and nationally.

(ii) The station status report which lists necessary jobs for maintenance or improvement of performance.

ESTIMATE OF PLANNED OUTAGE TIME

2. The length of the planned outage is decided by the following procedure:

(*a*) Decide on the minimum possible planned outage time; this will be the maximum of:

(i) statutory outage;

(ii) routine maintenance (ie work which will not last until next planned outage);

(iii) restoration of plant out of service.

(*b*) Decide what additional work can be planned into the outage time:

(i) select cost/effective jobs from the list, ie those which pass the financial criteria;

(ii) rank jobs in order of effectiveness;

(iii) allocate resources to jobs until either

(1) the limit of resources is reached or

(2) target availability estimate is reached.

ESTIMATE OF RECURRENT COMPONENT OUTAGE

3. From historical data the probability of each item of plant breaking down in a given period can be estimated. These probabilities will be modified by the additional work put into the planned outage and the level of effort in preventative maintenance. By combining the outage probabilities for each plant item an estimate of the time for which a set is less than 100 per cent capable can be made. The Midlands Region is developing a mathematical model to calculate the probability that a set will be in one of five stages, representing full and partial capability at any given time.

ESTIMATE OF NON-RECURRENT OUTAGE

4. There is no statistical base for the estimation of non-recurrent outages item by item, but an indication of the total effect over all plant can be estimated from historical performance.

PREDICTING THERMAL EFFICIENCY

5. The method of predicting thermal efficiency is similar to that for availability. The steps are listed below:

(i) The starting base for predicting thermal efficiency performance is the post-commissioning heat balance and its regular updating by station efficiency department.

(ii) The circuit losses are listed item by item and the cost is estimated for unit efficiency change in each. Table 1 shows this tabulation for Fawley.

(iii) The historical trend performance in terms of annual per cent charge is recorded item by item.

(iv) Options for improvement are listed with cost and assessed against the financial criteria of return and pay back period.

(v) The projects are ranked and resources allocated in order until either

(a) all resources are fully utilised, or

(b) the target prediction of thermal efficiency is reached.

6. Finally, the prediction of thermal efficiency can be made by combining an estimate of the heat loss made good by the projects undertaken and the measurement of current thermal efficiency.

TABLE 1 **Fawley Power Station 500 MW unit efficiency and cost data**

Operating parameter	*Deviation + or −*	*Unit efficiency change*	*Cost per 500 MW-day £*
Turbine			
steam pressure	3 bar	0·01	25
main steam temperature	10°C	0·09	225
reheat pressure drop	10°C	0·10	245
reheat pressure drop	0·5 bar	0·03	75
Condenser pressure	3 mbar	0·12	295
Final feed water temperature	1°C	0·01	27
Steam driven feed pump	Out of service	0·40	1,000
Single bank of hp heaters	Half-bank	0·70	1,800
No 7A or 7B hp heater	Out of service	0·40	1,000
No 6 hp heater	Out of service	0·06	160
No 5 hp heater	Out of service	0·03	78
Boiler gas oxygen content	1%	0·09	220
Boiler gas hydrogen content	0·1%	0·02	50
Boiler gas CO content	0·1%	0·13	320
Final gas temperature	10°C	0·14	340

Source: The CEGB

APPENDIX 16

(Referred to in paragraph 6.84)

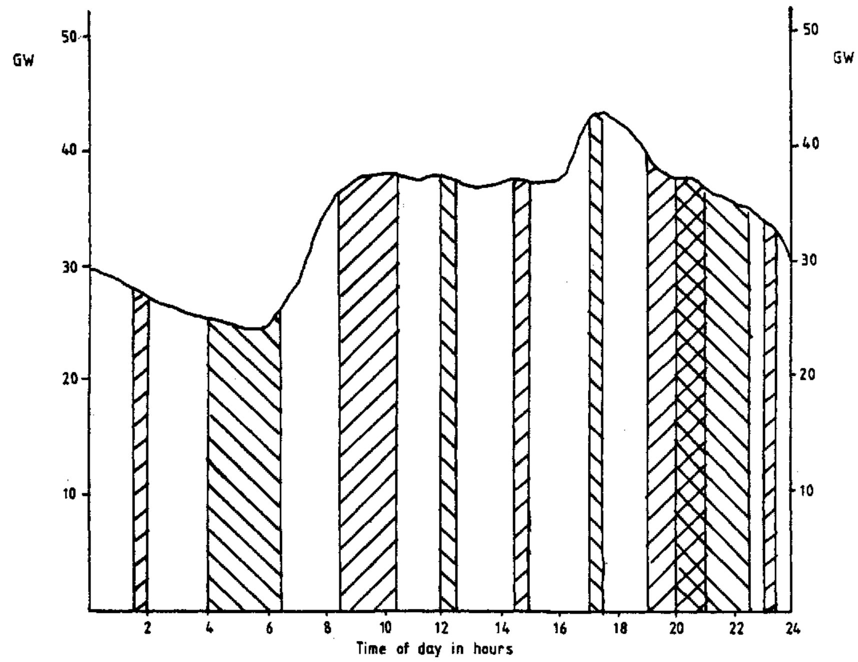
Costing periods used for optimising generation costs during daily load variations

1. Figure 1 shows the relationship between the costing periods and the shape of the daily demand curve. In general the costing periods correspond to turning points on the curve. The costing period represents one half hour over which the demand is average. The shape of the demand curve varies throughout the year and the position of the peaks and troughs will vary between certain limits. These limits are shown in Figure 1. The half hour costing periods for any given day will lie between these limits and will be chosen to coincide with the turning points.

2. Table 1 tabulates the current costing periods used at National Control.

FIGURE 1

The costing periods used at National Control applied to a Typical Winter Weekday Demand Curve



Source: The CEGB

TABLE 1

Current costing periods

Period	Definition	Weekdays half hour ending from	Weekdays half hour ending to	Saturdays half hour ending from	Saturdays half hour ending to	Sunday half hour ending from	Sunday half hour ending to
1A	Fixed time		02.00	As weekday		3.00	
1B	Night minimum demand	04.00	06.30	As weekday		As weekday	
2A	Morning peak	08.30	10.30	09.30	11.00	Fixed 10.30	
2B	Midday peak	12.00	12.30	12.00	13.00	12.30	13.00
3A	Mid afternoon peak(*)	14.30	15.00	As weekday		14.30	
3B	Afternoon trough (*)	None		15.30	16.30	15.30	16.30
3C	Teatime peak	17.00	17.30	17.30	18.00	17.30	18.30
4A	Evening trough	19.00	21.00	As weekday		None	
4B	Evening peak	20.00	22.30	As weekday		As weekday	
4C	Fixed time	23.30		As weekday		As weekday	

*One of these periods to be requested at the discretion of the National Control engineer.

Source: The CEGB

APPENDIX 17

(Referred to in paragraph 7.55)

The basic principles of the generation of energy from nuclear fuels and the fuel cycle

Introduction

1. This appendix is intended to assist the non-technical reader to an understanding of the text in Chapter 7 concerned with the procurement of nuclear fuel. It is a very simplified account of the nuclear process and its application to power generation and the resulting fuel cycle. The process of simplification has inevitably led to some omission and perhaps also to a loss of appreciation of the great scientific and engineering difficulties involved in the design and construction of a practical nuclear power system. Readers wanting more detail should consult one of the standard texts such as 'Source book on Atomic Energy' by S Glasstone or the sixth report of the Royal Commission on 'Environmental Pollution, Nuclear power and the Environment' (Cmnd 6618). We set out in this appendix the physical principles which allow the useful generation of energy from nuclear fissions, and why some reactors need fuel which has been enriched in fissionable material. We also discuss the possibility of Fast Reactors and their value in breeding fissionable fuel. Finally we outline the concept of the fuel cycle and nuclear wave management.

The Source of Nuclear Heat and the Chain Reaction

2. The source of heat energy in nuclear reactors derives from the 'fission' process. Nuclear fission occurs when the nuclear material of certain elements divides into two. The resulting two pieces of nuclear material are called 'fission' fragments each representing new chemical elements distinct from the original. The significant factor in fission is that the combined mass of the resulting fission fragments is less than the mass of the original nucleus, the lost mass having been converted into energy which eventually appears as direct heat. The fission fragments give rise, through the decay process, to fission products. Fission products form a wide variety of chemical elements, many of which are biologically toxic, and most are highly radioactive.

3. Fission occurs spontaneously in very few natural elements but can also be induced by the interaction of the nuclear material with a sub-nuclear particle called a neutron. The induction process is of great importance because neutrons are themselves a product of the fission process. A self-maintaining nuclear process, the chain reaction, is possible if neutrons produced in fission can be made to induce further fissions. This will occur if at least one neutron from each fission produces one further fission. The condition known as 'critical' occurs when each fission induces exactly one further fission. This is the normal running condition of a reactor where fission and thus heat are produced continuously, but under perfectly stable control.

4. Natural uranium is a favoured nuclear material because it undergoes spontaneous fission at a very slow rate and can also undergo induced fission with neutrons. Thus when used in a reactor the spontaneous or natural fissions can be used to 'prime' or start the chain reaction, and the neutron induced fissions can be used to maintain it and control the output power.

5. The spontaneous fission rate in natural uranium is so small that the resultant fission products are insignificant and present no hazard in the natural state. It is only after taking part in the chain reaction in a reactor that the volume of accumulated fission products presents a hazard. The radiation hazard from the fission products will reduce naturally over a period of time because of the radioactive decay process. The time period will, however, generally be very long.

6. One of the products produced in uranium which has been irradiated in a reactor is the element plutonium which does not occur naturally. It is not a fission product but is produced by nuclear transmutation when the uranium nucleus absorbs a neutron without producing fission. Plutonium is a fissionable material able to sustain chain reactions. Thus in a nuclear reactor it is possible for fuel to be burnt and generated at the same time. This is called 'breeding'. Normally the ratio of burnt to generated fuel, the breeding ratio, is less than one and there is a net consumption of nuclear fuel. With very careful design breeding ratios greater than one may be obtained with a net generation of useable nuclear fuel.

Thermal, Fast and Breeder Reactors

7. The ease with which nuclear material can be made to undertake neutron-induced fission depends both on the type of nuclear material and on the energy associated with the inducing neutron. Uranium undergoes fission most readily with low energy or 'thermal' neutrons. However, the neutrons produced in the fission process are mostly of high energy or 'fast'. To maintain a chain reaction therefore, the neutrons must be reduced in energy or 'thermalised'. This is accomplished by allowing the fission-inducing neutron to pass through a material called a 'moderator', which reduces their energy, before again reacting with uranium. We shall see later that the choice of moderating material is very limited and can lead to the need for enriched uranium as a fuel. Thus a 'thermal' reactor is one in which fissions are induced by 'thermal' neutrons produced by means of a moderating material.

8. Some material such as plutonium can undergo induced fissions with fast neutrons. Thus a reactor based on plutonium would not require a moderator and is called a 'fast' reactor. The neutron density inside a fast reactor will be higher in consequence than in a thermal reactor. Plutonium is produced when neutrons are absorbed in uranium nuclei without producing fission. In a fast reactor it is possible to place a quantity of 'depleted' uranium (see later) close to the centre and allow it to absorb leaking neutrons and 'breed' without impairing the chain reaction process. A fast reactor which has an envelope of 'depleted' uranium for 'breeding' fissionable plutonium is called a 'Fast Breeder Reactor'.

The Thermal Reactors—MAGNOX, AGR, PWR—and the need for enriched Uranium

9. Natural uranium consists of two slightly different forms of the uranium element, called isotopes; U235 which is the fissionable material and U238 from which plutonium may be made. The two forms are found in natural uranium mixed in a constant proportion, but the fissile U235 forms only 0·7 per cent of the natural material. To design a reactor that will work with natural uranium is difficult because of the low proportion of fissile material present and it is only just possible to achieve criticality. In particular it is very important to prevent any loss of the fission-produced neutrons, either through escaping from the reactor zone or by absorption in non-fissionable material, otherwise there are too few neutrons to maintain the chain reaction.

10. Thus for a natural uranium reactor the material of the moderator and of the fuel element must have low neutron absorbing properties. In a 'Magnox' reactor the moderator is graphite, the heat transfer fluid is carbon dioxide, the uranium is in the form of uranium metal and the uranium is enclosed (canned) in an alloy of magnesium called 'MAGNOX'. Both magnox and uranium metal have low melting points which restricts the temperature at which the reactor can work. The magnox reactor gives rise to a steam temperature less than that of present conventional boilers and therefore gives a poorer thermal efficiency performance from the turbine whose efficiency depends on the input steam temperature.

11. To increase the working temperature of the reactor the uranium must be in the form of the oxide and the fuel canning material must be of a material with a high melting point such as stainless steel. Under these conditions it is not possible to sustain a chain reaction with natural uranium because of the neutron absorption in the stainless steel. If, however, the natural uranium is enriched in the fissile isotope U235 then a self-sustaining chain reaction can be achieved and a high temperature reactor can be designed, such as the AGR. The AGR uses graphite moderators, carbon dioxide as a heat transfer fluid and enriched uranium oxide encased in stainless steel as a fuel.

12. Given a slightly higher degree of enrichment it is possible to dispense with the graphite moderator and carbon dioxide transfer fluid and to use ordinary water for both purposes. This is the basis of the pressurised water reactor, the PWR.

13. The process of enrichment starts with natural uranium, which consists mainly of U238 with a small amount of U235 (see paragraph 9). The material is split into two streams. The fissionable U235 is gradually extracted from one stream and added to the other so that one becomes 'enriched' in U235 and the other 'depleted' in U235. For the AGR the uranium is enriched in the isotope U235 so that its proportion is raised to about 2·5 per cent of the resulting mixture of uranium isotopes, while for the PWR the natural uranium is enriched in U235 to about 4 per cent.

14. The separation process depends upon the slight differences in physical properties between U235 and U238. In one, the diffusion process, the separation depends on the small difference in diffusion of the two isotopes in the gas uranium hexafluoride, and in the other on the small difference in the centrifugal forces on the two isotopes in uranium hexafluoride in a high speed centrifuge. Because the difference in properties is so small the process must be repeated many times in cascade using considerable quantities of energy, and it is therefore costly. However, the centrifuge process requires less energy than the diffusion process for the same degree of separation.

15. It is possible, if new sources of uranium are scarce or expensive, to return the depleted uranium fraction through the enrichment process to produce two further fractions, one with a proportion of U235 similar to natural uranium and the other very highly depleted. Reactor depleted uranium recovered by reprocessing in irradiated fuel can also be used. There is an important economic advantage in using fast reactors or enriched thermal reactors in that the power density, ie the MW per litre of reactor volume, is increased and a smaller reactor can produce the same power output with consequential capital savings.

The Fuel Cycles

16. A consequence of the fission process taking place in any reactor is the build-up of fission products in the fuel. Many of these fission products are 'nuclear poisons' in that they are very efficient absorbers of neutrons thus reducing the number available to help maintain the chain reaction. Eventually a chain reaction will not be sustainable, even though there is unused nuclear fuel still left in the reactor, and the reactor will stop.

17. It is necessary therefore to refuel the reactor before all the nuclear fuel is used. The decision then arises as to whether to recycle the used fuel by extracting the fission products and returning the unused fuel to the reactor, or to dispose of it safely and always use new uranium as fuel.

Nuclear Waste Management

18. The recycling decision is closely related to the safe management of the irradiated fuel and its associated fission products. Irradiated fuel, extracted from the reactor, is associated with three hazards:

(i) it is still producing significant quantities of heat as the result of the radioactive decay of the fission products and therefore must be cooled until the heat evolution decays;

(ii) it contains biologically very toxic material and must therefore be contained;

(iii) it emits dangerous ionising radiations and therefore must be shielded.

19. These objections can be met, in the short term, by placing the fuel in water or in a flow of gas in a shielded store made of concrete or steel. Magnox will corrode under water in a relatively short period but it is technically feasible to store either type of fuel for quite long periods in a controlled

dry gas atmosphere. However magnox is less stable than stainless steel unless it is kept under a very strictly controlled environment and long-term dry storage of magnox is not considered economic.

20. Thus long-term storage for magnox elements is not practicable and the fuel must be processed to produce a safe and convenient form for waste disposal. However long-term dry storage of unprocessed irradiated AGR fuel is, followed eventually by reprocessing, feasible.

21. Waste processing and fuel cycling consists of the following steps:

(i) stripping the magnox fuel element of the canning material, and chopping the stainless steel clad AGR elements into short pieces;
(ii) dissolving the uranium metal or oxide, including fission products, in an acid;
(iii) separating the plutonium and uranium from the acid;
(iv) separating the plutonium from the uranium;
(v) the remaining liquor containing the dangerous fission products can be stored in the short term in cooled stainless steel vessels.

The long-term waste proposal is to concentrate the liquid waste then to mix it with silica and borax and heat it to a high temperature. This process produces a glasslike substance in which the fission products are embedded. The process has two advantages: first, it reduces the volume of the wastes considerably, and secondly, it produces a very stable and strong material from which it is very difficult to leach out the fission products. This process is called the vitrification process.

22. The vitrified waste can then be encapsulated and placed in a shielded container. Disposal of the encapsulated material on the ocean bed or deep in suitable geological formations is currently considered to offer the best solution to long-term management of nuclear waste. Investigations are still being undertaken to ascertain whether these modes of disposal can be considered perfectly safe.

23. Fuel reprocessing is a specialised chemical engineering process. It must be undertaken under remote operation in a carefully controlled and contained environment. Whilst the chemical processes involved are used in other industrial applications, the very nature of the material involved makes it a unique operation.

APPENDIX 18

(Referred to in paragraph 11.14)

Historical Initiatives on Management Information Systems

1. This appendix sets out the initiatives by the Board during the period of 1963 to the early 1970s to rationalise the Board's Management Systems.

1963 Working party on revenue costs and budgets

2. This work started as a Regional initiative in the SW Region. The intention of the working party was to compare the various working methods across the Regions. They planned to investigate variations costs and to produce management ratios and cost yardsticks, which might form the basis of a standard approach. Some work was done but no formal conclusions were reached.

1963 commercial data processing standardisation working party

3. In 1963 the Deputy Chairman, Mr Owen Francis who chaired a Computer Applications Committee, convened a working party to develop four standard Management Systems:

- payroll and personnel statistics;
- purchasing and stores control;
- costing and financial accounting;
- fuel accounts and statistics.

4. The working party was chaired by the Deputy Financial Controller and working groups were set up in four Regions. The central working party included the Project Leaders, Computing Branch Managers for the Regions and the Senior Financial Officers and O & M Officers from Headquarters. The working party was in operation from 1963 to 1973.

Payroll and personnel statistics

This system was developed in the NE Region in association with a national working party and implemented throughout the Board. Local variations have been introduced to meet each Region's special requirements.

Purchasing and stores control

A fully operative system was developed in NW Region and commissioned in a number of power stations. The accounting policy was controversial and gave rise to problems with external audit. The system was not implemented nationally.

Costing and financial accounting

Very little development was achieved because the other systems being developed provided inputs, not all of which were finally accepted. The system was further deferred because of the need to develop a new national cost code.

Fuel accounts and statistics

The system was developed in the Midlands Region in association with a national working party and implemented nationally.

1963 management information flow studies

5. A working party set up under the Deputy Chairman was to investigate the information needs of Operations, Finance, Personnel and Commercial Departments. The work concentrated on the engineering information flows on availability and reliability. The only direct outcome was revision of the 'Plant Reliability/Availability' (PRA) reporting system.

1964 standardisation of reporting

6. The Central Executive Committee requested that all Regional forms should be standardised. The action was delegated to Engineering Standards Branch. The potential for a management information approach was not appreciated and no progress was made.

1970 standard forms of information reporting

7. Central Management Services undertook a study of standard forms of information presentation. A memorandum by the Chairman to the Executive recommended that a redefinition of Management Information requirements should be undertaken:

> 'Management Information is concerned with monitoring the end results of the Board's efforts and should be closely linked with commerical performance. Such requirements must emphasise the objectives of the Executive in their proper commercial priorities and provide an accurate and complete monitoring of success or failure.'

8. The Chairman also pointed to the need for revised information requirements in the field of operations and Regional monitoring, the emphasis was on setting a satisfactory budget in terms of fuel, manpower and other costs. Monitoring was to be based on comparisons of budget and actuals for station output, thermal performance, fuel costs and other costs. The aim was to assess commercial performance. The result of the Chairman's initiative was that such systems have been implemented nationally.

9. A number of other systems have been implemented nationally having originated as the initiatives of Headquarters or Regional chief officers. These are described in Chapter 11 but listed here for completeness:

— Station Thermal Efficiency Performance (STEP)
— Computer Assisted Systems Operations (CASO)
— Plant Reliabiliy/Availability (PRA)
— Financial Information and Budgeting System (FIBS)
— Power Station Work Planning Real Time System (KISMET).

APPENDIX 19

(Referred to in paragraph 11.20)

Station Commercial Operation Performance

1. The 'SCOPE' factor is intended to display the commercial performance of the power station in terms of its contribution to reducing Board costs.

2. The SCOPE factor is defined as follows:

$$\text{SCOPE} = \frac{\left\{\begin{array}{l}\text{POTENTIAL VALUE} \\ \quad - \text{Loss of capability available} \\ \quad - \text{Flexibility loss} \\ \quad - \text{Thermal efficiency loss}\end{array}\right\}}{\text{POTENTIAL VALUE}} \times 100$$

(*a*) *Potential value* is calculated as the reduction in fuel cost to the national system, in the context of the actual generating conditions when all targets are just met.

(*b*) *Flexibility* is measured in terms of the ability of plant to shut down overnight, or a period of at least five hours during a weekend trough. This is applied to different types of station as shown in Table 1.

TABLE 1 **Target flexibility**

Type	*Flexibility target*
Nuclear	Not applicable
500 MW coal	Any one unit
500 MW oil	Any two units
100/120 MW	All units simultaneously

(*c*) *Thermal efficiency* is measured in terms of the 'STEP' factor, which relates the actual to the theoretically achievable thermal efficiency of the particular station adjusted for factors outside the control of the station, for example the operating and loading regime required by Area Control.

3. Table 2 shows the SCOPE factors calculated for a number of stations in the SW Region for the year 1979–80.

Table 2 **Station Commercial Operating Performance (SCOPE)**

1979–80

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Availability				
	Potential Value	*Overhaul Excess*	*Breakdown + OSC Excess*	*Flexibility Loss*	*Thermal Efficiency Loss*	*Scope* $\frac{(2)-(3)-(4)-(5)-(6)}{2} \times 100$
	£000	£000	£000	£000	£000	%
Magnox						
Berkeley	21,400	6,435	−137	—	47	70
Hinkley Point A	36,980	3,022	1,798	—	20	87
Oldbury on Severn	37,325	−1,561	−1,795	—	94	109
500 MW Coal						
Aberthaw B	25,023	3,069	4,480	294	2,789	58
Didcot	36,659	2,452	7,982	518	4,688	58
500 MW Oil						
Fawley	18,194	−906	−234	1,769	−322	98
Pembroke	19,900	−508	−615	1,509	−1,106	104
100/120 MW						
Aberthaw A	7,888	652	−308	16	1,383	78
Uskmouth B	5,129	−164	351	31	499	86
AGR						
Hinkley Point B	75,431	12,254	8,101	—	513	72

Source: The CEGB

Appendix 20

(Referred to in paragraph 11.26)

List of Principal Programs run on Regional Mainframe Computers and at HQ

1. **South Eastern Region**

National payroll and personnel statistics
Trade creditors
Stores
Accounting scheme
STEP factor
Kingsnorth power station defect reporting system
Grain power station defect monitoring system
Littlebrook 'D' defect reporting system
Dungeness routine maintenance and history
Bulk supply system
Film badges
Drawing records index
Plant spares catalogues
General stores catalogues
Generation statistics
Annual budget

2. **South Western Region**

Stores recording system
Work planning
Plant inventory management system
Stores catalogue system
Routine operation and maintenance processing
Location information for monitoring of budgets
Stores ledger movement updating
Costing monthly procedure
Invoice payments
Payroll system
Bulk supply system
STEP factor
Plant reliability and availability reporting scheme
Project evaluation and review techniques (PERT)
National data catalogue system

3. **Midlands Region**

STEP factor
Plant reliability and availability reporting scheme
Bulk supply system
Project evaluation and review techniques (PERT)
Capital and revenue contracts
Payroll and personnel records and statistics

Creditors' payments
National contracts
Vendors
Predetermined cost and non-contract description update
Production of orders
Outstanding orders
Purchase progressing

4. **North Eastern Region**

National payroll and personnel statistics
Finance information and budgeting system
Ordering and purchasing
Real time stores system
Stores accounting
Power station work planning
Bulk supply system
STEP factor
Coal analysis
Wages and salaries costing
Superannuation and pensions
Cheque payments
Capital expenditure
Plant availability
Plant history
Fuel forecasting
Fuel allocation

5. **North Western Region**

Stores accounting and catalogue
Invoices
Debtors
Miscellaneous costs
Wages costing
Budget monitoring
Capital depreciation
Wayleaves
Cost and financial accounting
Payroll
Manpower planning
Contract control
Training records
STEP factor
Plant reliability and availability reporting scheme
Project evaluation and review techniques (PERT)
Commitment planning
Generation costing
Works planning
Bulk supply system
Drawings index
CO2 Oxidation

General boiler monitoring
Wylfa and Trawsfynydd fuel irradiation
National data catalogue

6. These are supplemented by a very large number of scientific and technical programs available at HQ CC, many of which are suites of programs controlled by a supervisor system allowing engineers or operators to select the appropriate route for their application. Figure 1 illustrates the CASO system (Computer Aided Systems Operations) and Figure 2 illustrates the power system planning and design package. The central register of computer programs at HQ CC comprises six volumes:

ONE—Information and Management Control Systems

TWO—Power System Planning and Operations

THREE—Plant Design and Simulation

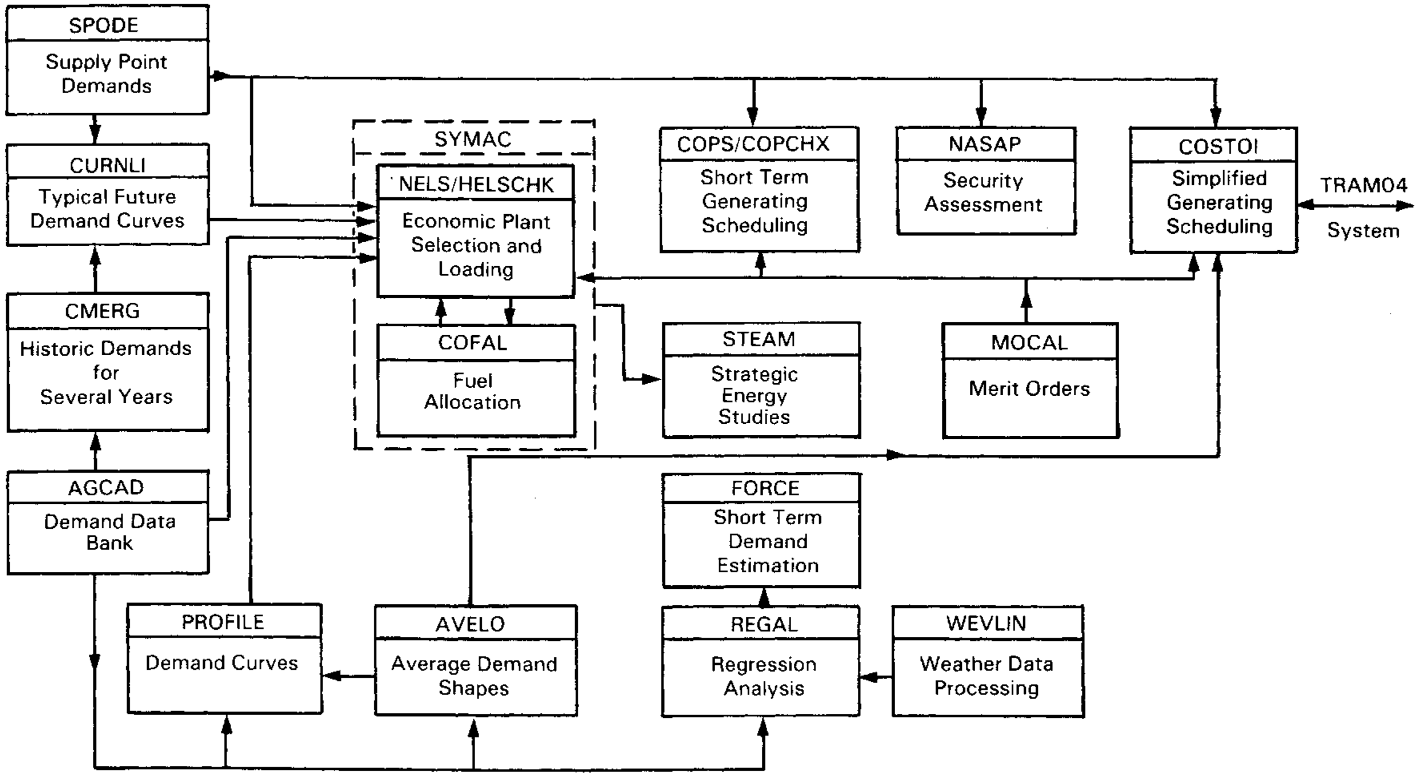
FOUR—Stress Analysis

FIVE—Nuclear Physics and Health Physics

SIX—Statistical Analysis, Mathematics and Science.

Figure 1

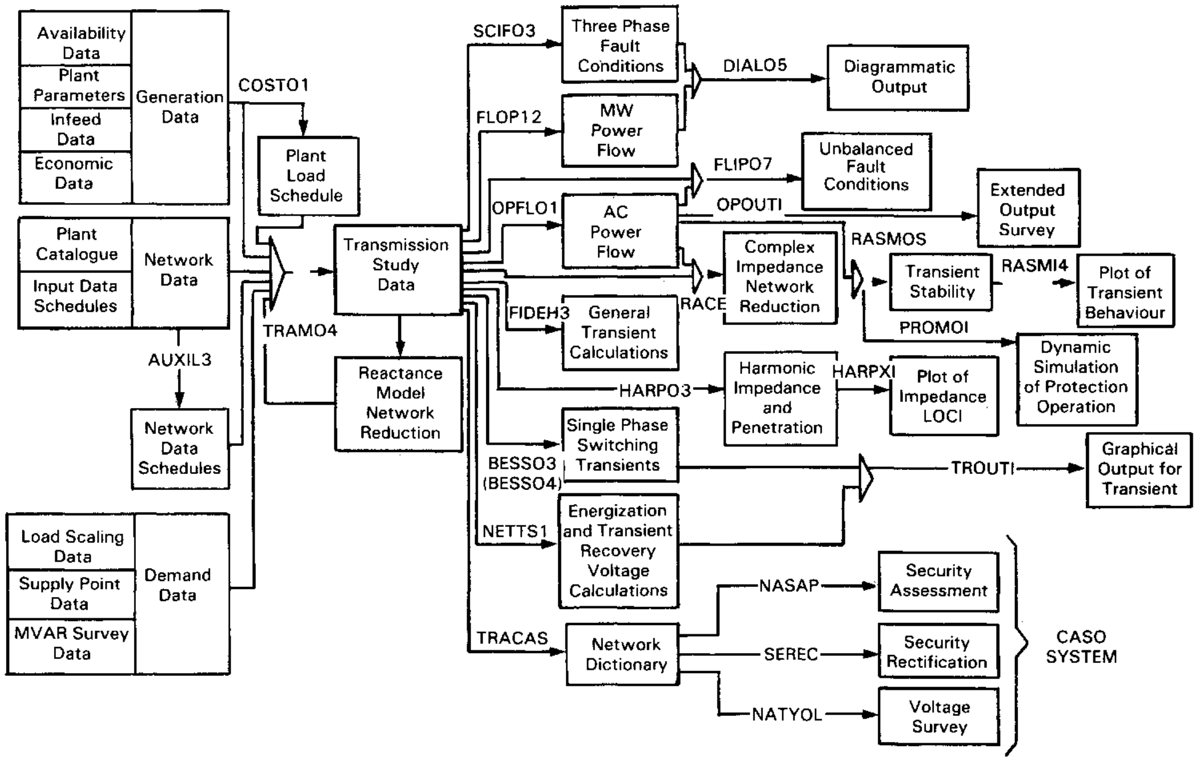
CASO time sharing conversational system of computer aids to system control engineers



Source: The CEGB

FIGURE 2

Power system planning and design package



Source: The CEGB

APPENDIX 21

(Referred to in paragraph 11.27)

Logical Information Flows and Main Decision Nodes in the Board's Four Principal Information Systems

1. Figures 1 to 4 set out the main logical flows of information in the Board's main information systems:

— planning and targeting

— technical performance

— budgetary control

— financial accounting.

Tables 1 to 4 describe the nature of the main decision nodes shown numbered on the figures, and indicate for each their relative importance as follows:

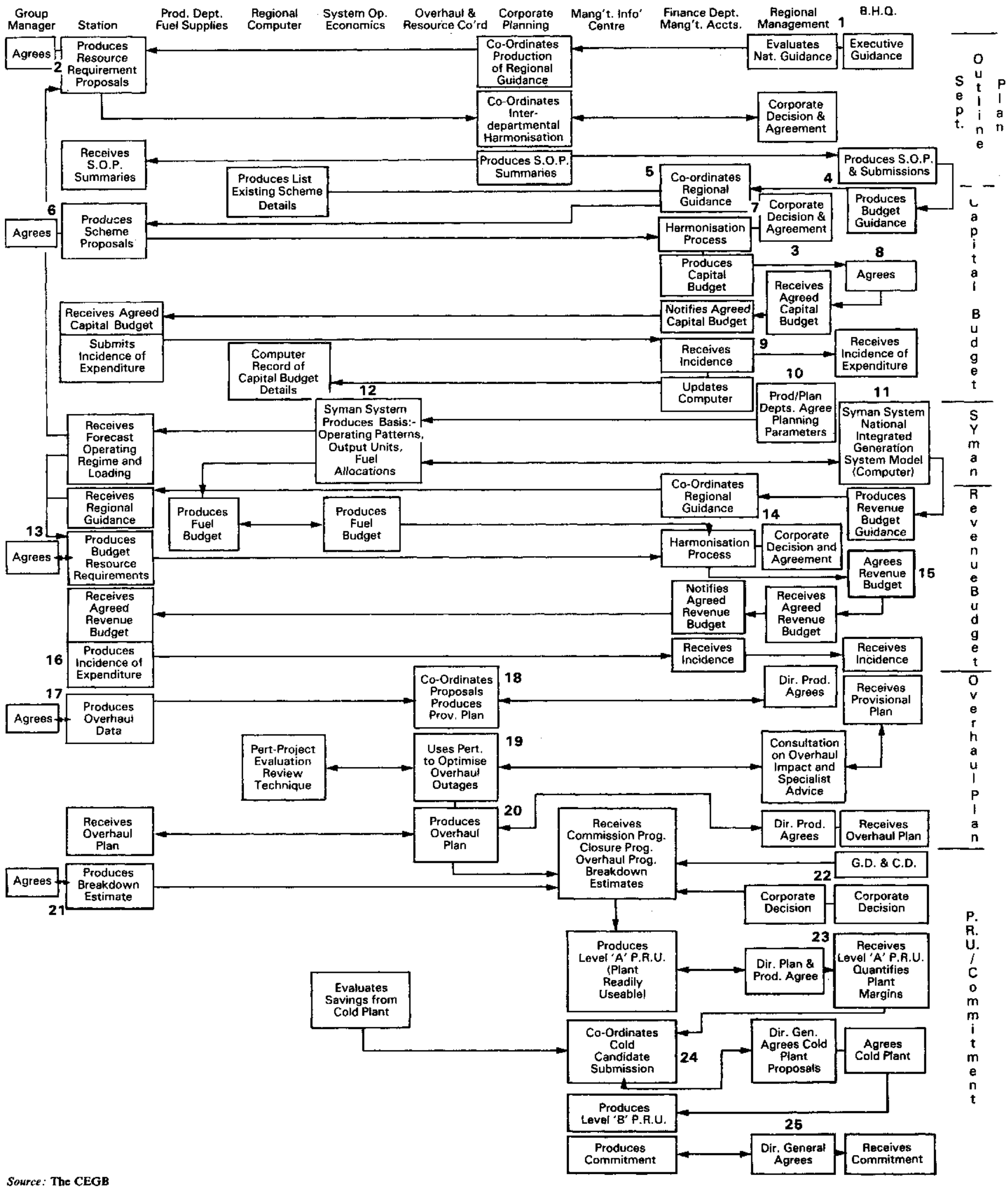
TYPE 1: *Key decisions* required for continual day-to-day operation of the system

Type 2: *Important decisions* with regard to the commercial/economic viability of the industry in the longer term

TYPE 3: *Other decisions.*

FIGURE 1

NW Region Cost and Performance Control System—Information Flows Planning and Target Setting



Source: The CEGB

Note: This is a greatly oversimplified representation of the system:

(*a*) All plans are mutually interdependent, and no order is implied by the diagram.

(*b*) All plans are based on rolling programmes looking up to 5 years ahead. These are continuously updated as significant changes occur.

(*c*) Although shown as single operations, plans such as overhaul and commitment, are in practice accomplished in two stages, looking 1 year ahead in detail and 2–5 years ahead in outline.

TABLE 1 **Planning and Target Setting**

(*Reference Figure 3*)

Decision Reference	*Decision Type**	*Decision Processes Involved*
1	2	The Board decides policy, and the Regional Management decides how best to implement the Executive Guidance.
2	2	Location Management has to decide upon resource requirements to meet SOP proposals.
3	2	Regional Management has to decide priorities in order to effectively harmonise individual requirements within the Executive Guidelines.
4	2	BHQ has to decide how to translate SOP submissions into Budget Guidance.
5	2	RHQ Finance Department has to link existing schemes and BHQ Budget Guidance, and decide Regional Guidance.
6	2/3†	Locations have to decide which schemes to submit and their priorities.
7	2/3†	RHQ has to harmonise scheme contributions and decide whether to accept or reject schemes.
8	2/3†	BHQ has to harmonise Regional Budget contributions and decide whether to accept or reject Budget.
9	2	BHQ/RHQ decide Scheme priorities, based upon overall financial considerations.
10	1	RHQ decides planning targets.
11	1	Automatic Decision Process to produce unit allocations, and optimise fuel distribution.
12	1	RHQ decides on Regional adjustments required to SYMAN output.
13	2	Location Management has to decide upon resource requirements to meet Budget.
14	2	RHQ harmonises location requirements and decides total Regional requirements.
15	2	BHQ harmonises Regional requirements and decides final Budget.
16	3	Location Management decides when and where to spend, within their Budget.
17	1	Location Management decides maintenance work required.
18	1	RHQ co-ordinates location proposals and decides upon a 'provisional' plan.
19	1	Automatic Decision Process (PERT) to optimise overhaul outages programme.
20	1	RHQ decides whether plan is suitable, and makes changes as required.
21	1	Location Management has to decide what level of plant breakdown to adopt (ie effectively deciding their commitment).
22	1	RHQ/BHQ corporately decides on station closure programme.
23	1	RHQ management decides whether to accept or amend Region's Level 'A' PRU submissions.
24	1	RHQ decides level of plant to make 'cold' (which depends upon Plant Margins from PRU submissions).
25	1	RHQ Management decides whether to accept or amend the final Level 'B' PRU submissions.

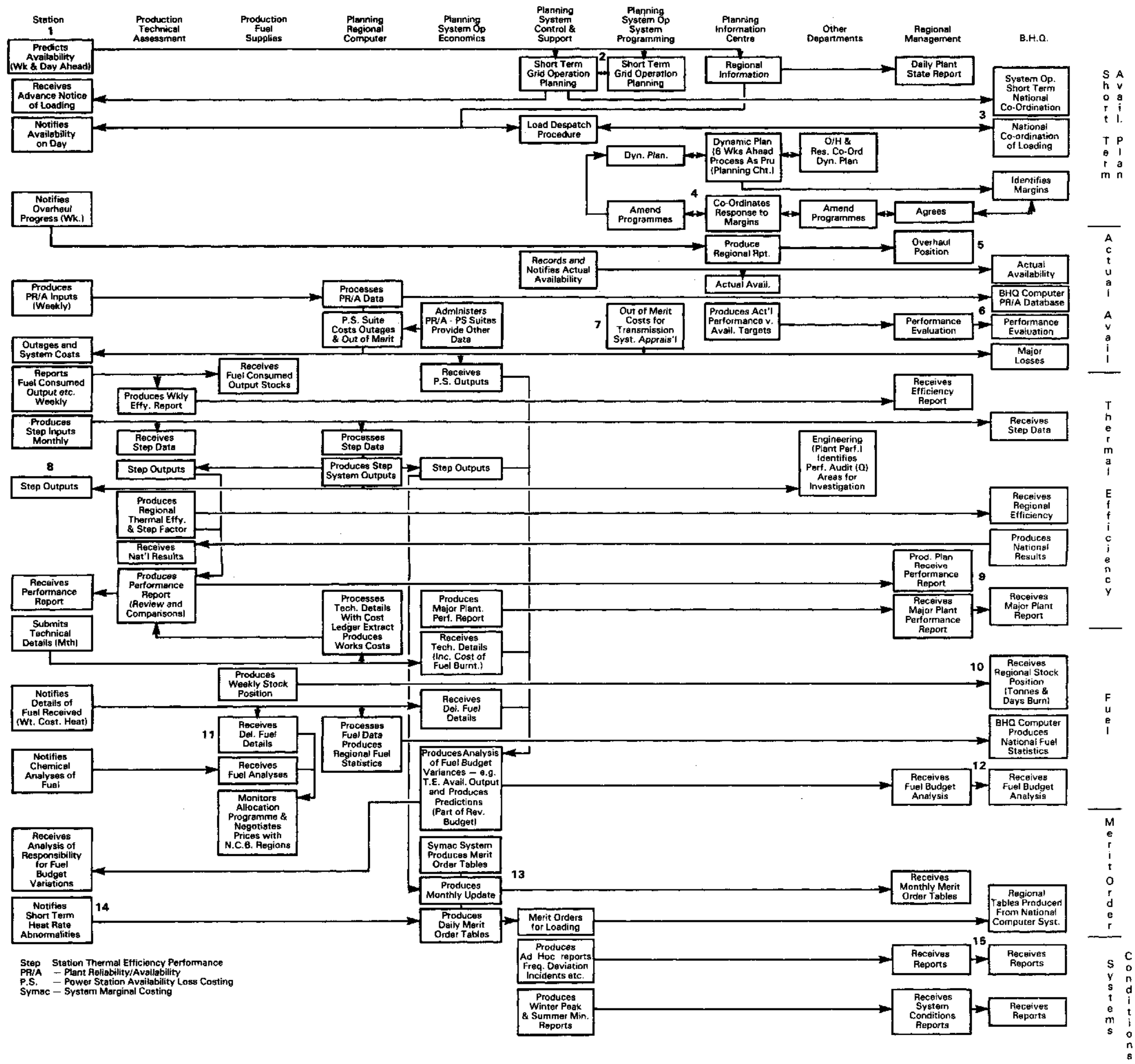
Source: The CEGB

* 1. *Key Decisions*—required for continual day-to-day operation of the System.
2. *Important Decisions*—with regard to commercial/economic viability of the Industry, in the longer term.
3. *Other Decisions.*

† Minor schemes are classified as Type 3.

FIGURE 2

NW Region Cost and Performance Control System—Information Flows
Technical Performance Control



Source: The CEGB

Note: Group Managers relationship to stations is not illustrated—being of a day to day management nature.

TABLE 2 **Technical Performance Control**

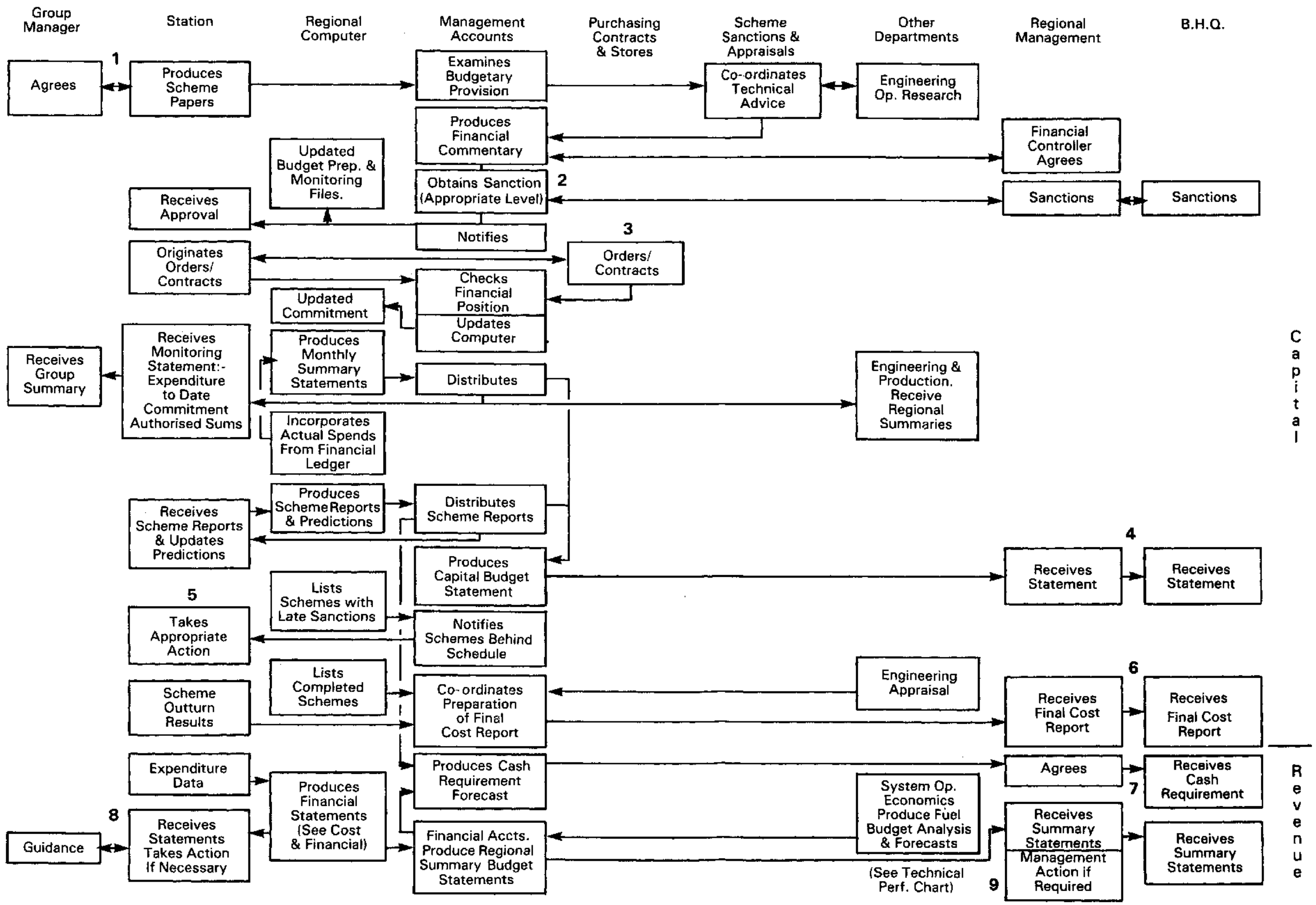
Decision Reference	*Decision Type**	*Decision Processes Involved*
1	1	Station Management decides what level of breakdown forecasts to adopt.
2	1	From station availability predictions decide System operating policy.
3	1	BHQ decides national loading pattern, taking into account System security and costs.
4	1	RHQ decides dynamic plans for System operation.
5	1	RHQ decides whether actions required to achieve targets, or whether to revise targets.
6	3	RHQ/BHQ decides whether action required to improve availability of plant.
7	1	Decisions on Transmission System planning, based on System security outage and costs.
8	3	Location Management decides whether action required to improve performance of plant.
9	3	RHQ/BHQ decides whether action required to improve performance of plant.
10	2	RHQ decides whether to alter delivery/stocking policies.
11	2	RHQ decides action with regard to NCB Fuel Supplies, ie Quality, Cost & Distribution.
12	3	RHQ/BHQ decides whether action needed re Fuel Budget.
13	1	Automatic Decision Process producing Plant Merit Order Table, for loading plant.
14	1	Locations sometimes have to decide whether to take operating plant out of service for maintenance (eg Feed Heaters).
15	3	RHQ/BHQ decides whether follow-up actions required.

Source: The CEGB

* 1. *Key Decisions*—required for continual day-to-day operation of the System.
2. *Important Decisions*—with regard to commercial/economic viability of the Industry, in the longer term.
3. *Other Decisions.*

FIGURE 3

NW Region Cost and Performance Control System—Information Flows
Budget Monitoring



Source: The CEGB

TABLE 3 **Budget Monitoring**

Decision Reference	*Decision Type**	*Decision Processes Involved*
1	2/3†	Location Management decides scheme options, priorities, implementation times etc.
2	2/3†	RHQ/BHQ decides whether to sanction schemes.
3	3	RHQ has to decide where and when to place orders and contracts.
4	2	RHQ/BHQ decides whether action to decrease spending required.
5	3	Locations decide what, if any, action required to accelerate relevant projects.
6	2	RHQ/BHQ establishes whether scheme was successful and decide whether to allow similar schemes in the future.
7	3	RHQ decides whether forecasts are acceptable.
8	3	Locations decide whether action required, and if so, what action.
9	3	RHQ decides whether action required, and if so, what action.

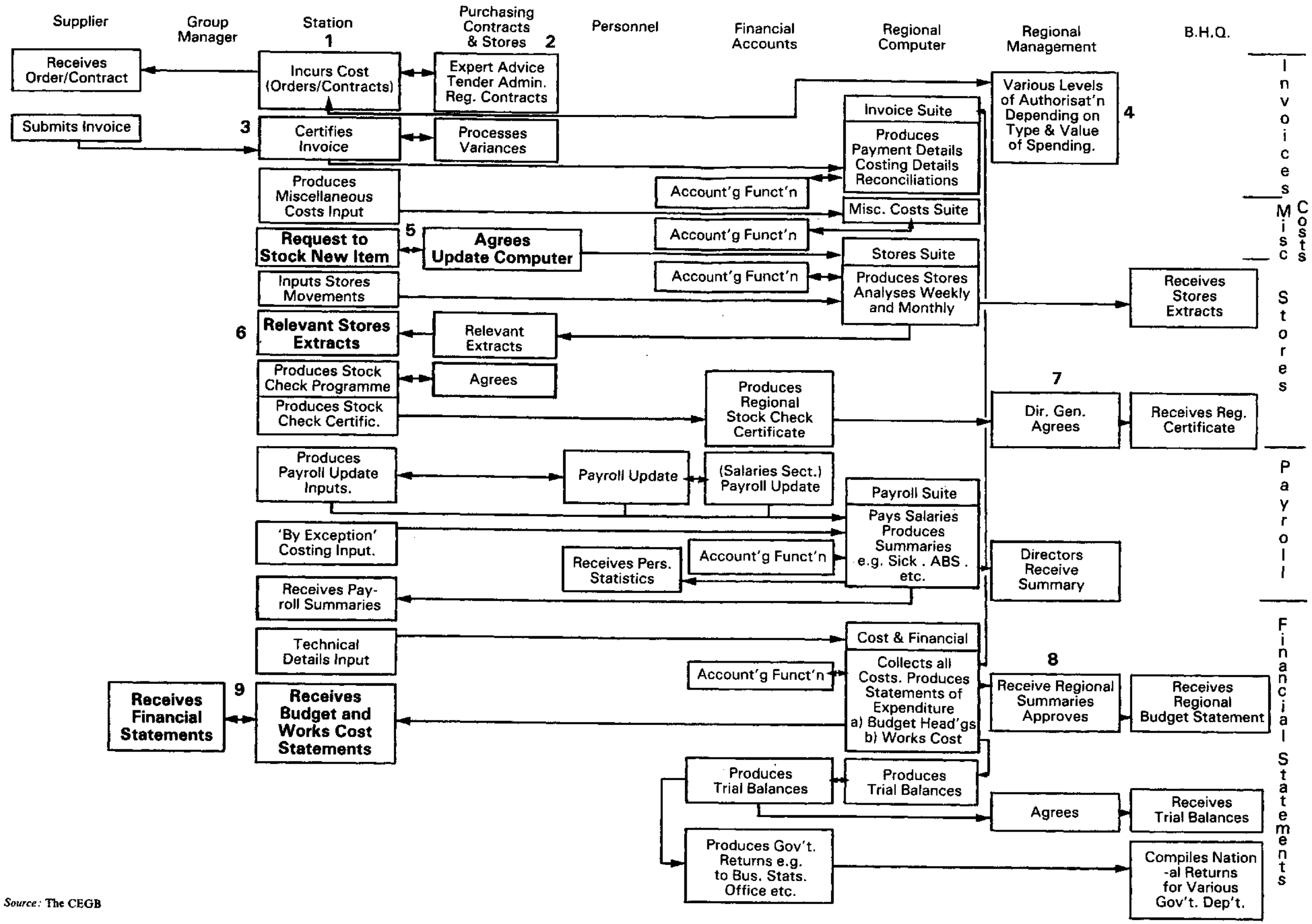
Source: The CEGB

* 1. *Key Decisions*—required for continual day-to-day operation of the System.
2. *Important Decisions*—with regard to commercial/economic viability of the Industry, in the longer term.
3. *Other Decisions.*

† Minor schemes are classified as Type 3.

FIGURE 4

NW Region Cost and Performance Control System—Information Flows
Cost and Financial Ledger/Expenditure Statements



Source: The CEGB

TABLE 4 **Cost and Financial Ledger/Expenditure Statements**

Decision Reference	*Decision Type**	*Decision Processes Involved*
1	2/3†	Location Management decides requirements.
2	3	RHQ decides where to purchase/place contracts.
3	3	Location Management decides whether to accept/certify invoice.
4	3	RHQ decides extent of spending authorisation.
5	3	Location/RHQ decides items to be stocked.
6	3	Locations decide whether action required as a result of stores extracts.
7	3	Director-General decides whether Regional Stock situation satisfactory.
8	3	RHQ decides whether action needed as a result of incidence of expenditure.
9	3	Location Management decides whether action needed as a result of incidence of expenditure.

Source: The CEGB

* 1. *Key Decisions*—required for continual day-to-day operation of the System.
2. *Important Decisions*—with regard to commercial/economic viability of the Industry, in the longer term.
3. *Other Decisions.*

† Minor schemes are classified as Type 3.

APPENDIX 22

(Referred to in paragraph 11.44)

The Board's Main Computer Installations

1. Figures 1 to 6 show the configuration of the major computer installations:

— Headquarters

— South Eastern Region

— South Western Region

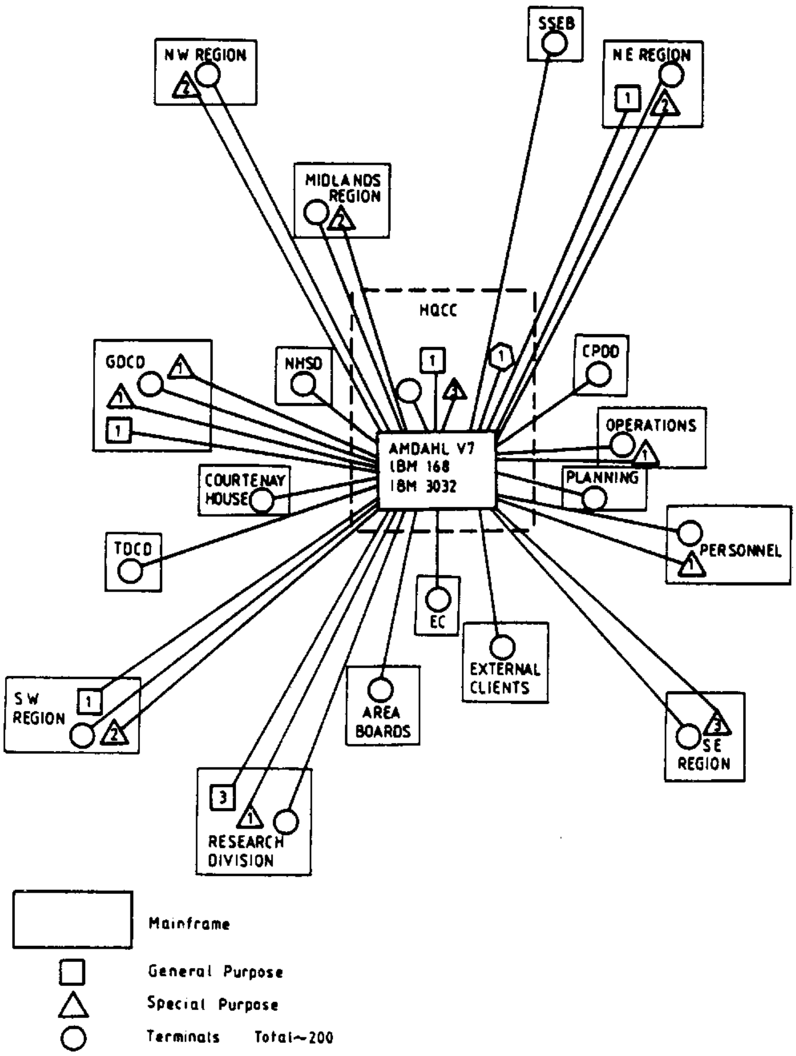
— Midlands Region

— North Western Region

— North Eastern Region.

FIGURE 1

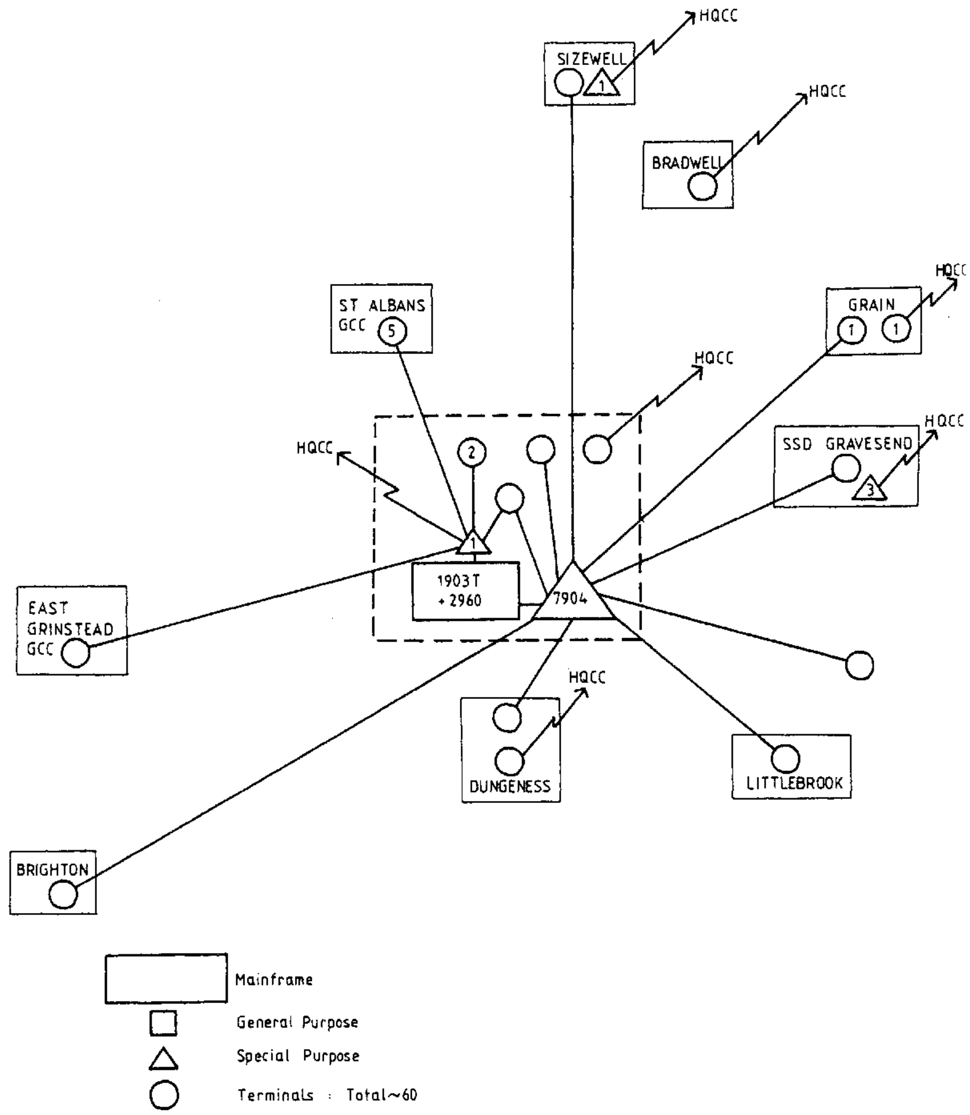
Computing Equipment—Headquarters Computing Centre



Source: The CEGB

FIGURE 2

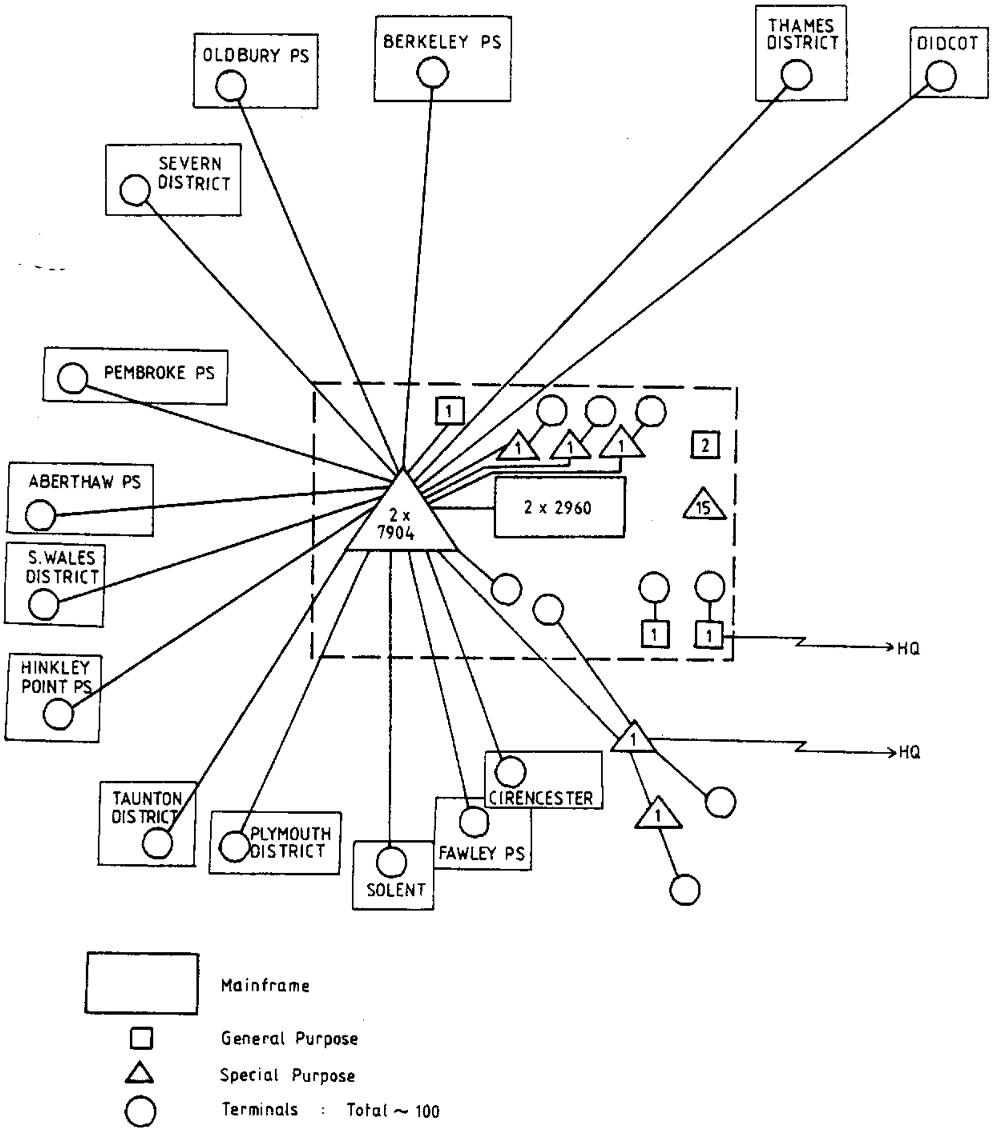
Computing Equipment—South Eastern Region



Source: The CEGB

FIGURE 3

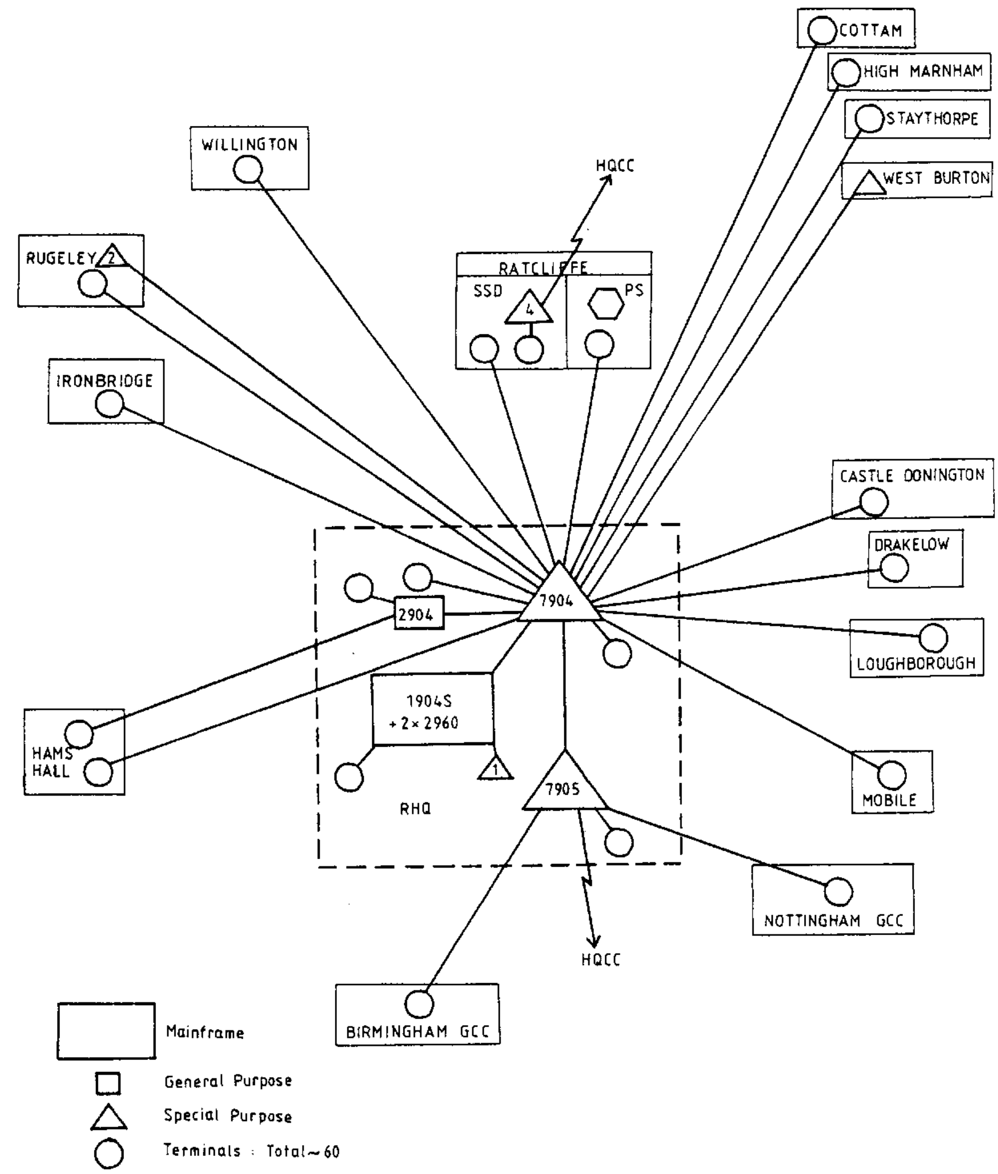
Computing Equipment—South Western Region



Source: The CEGB

FIGURE 4

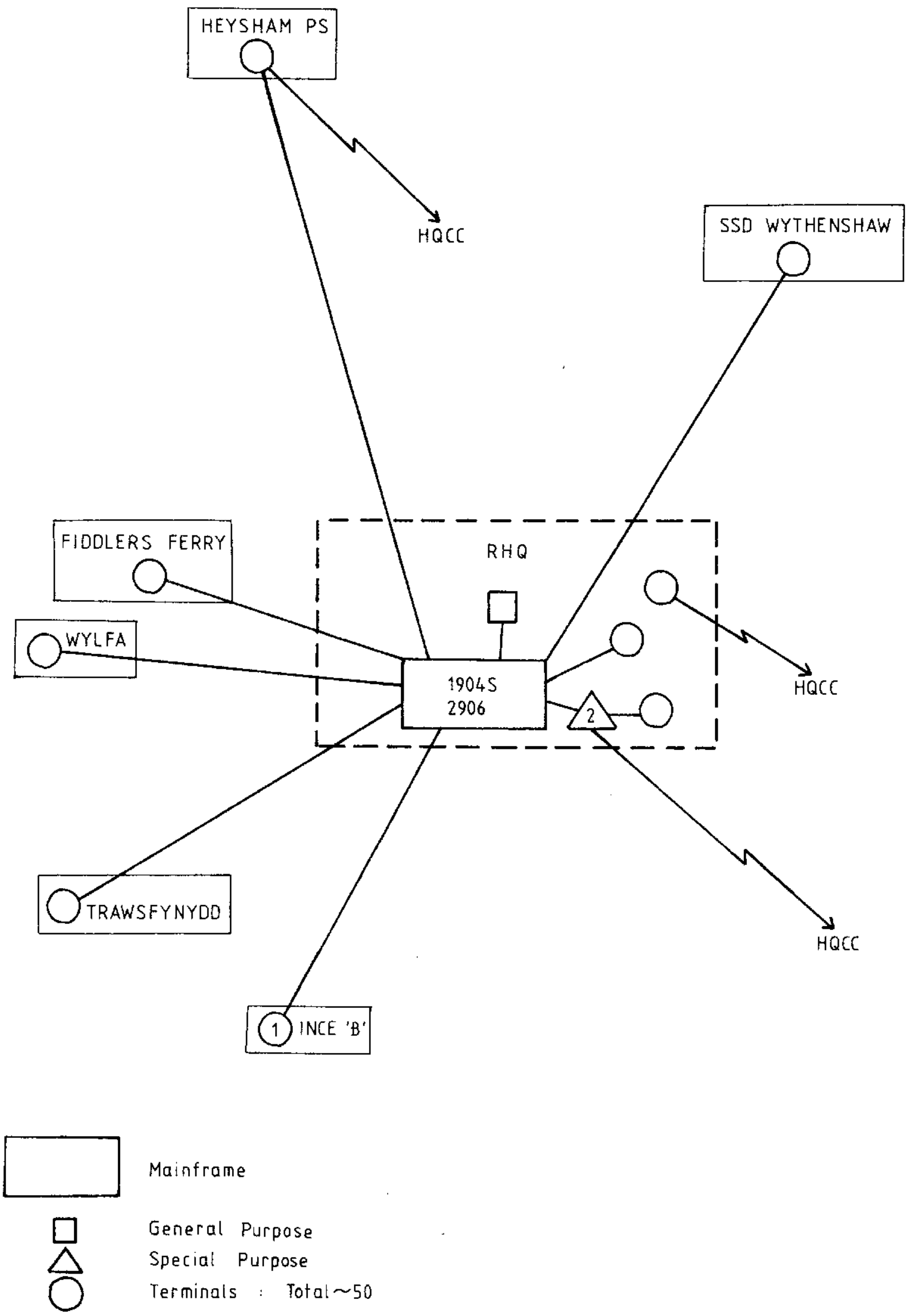
Computing Equipment—Midlands Region



Source: The CEGB

FIGURE 5

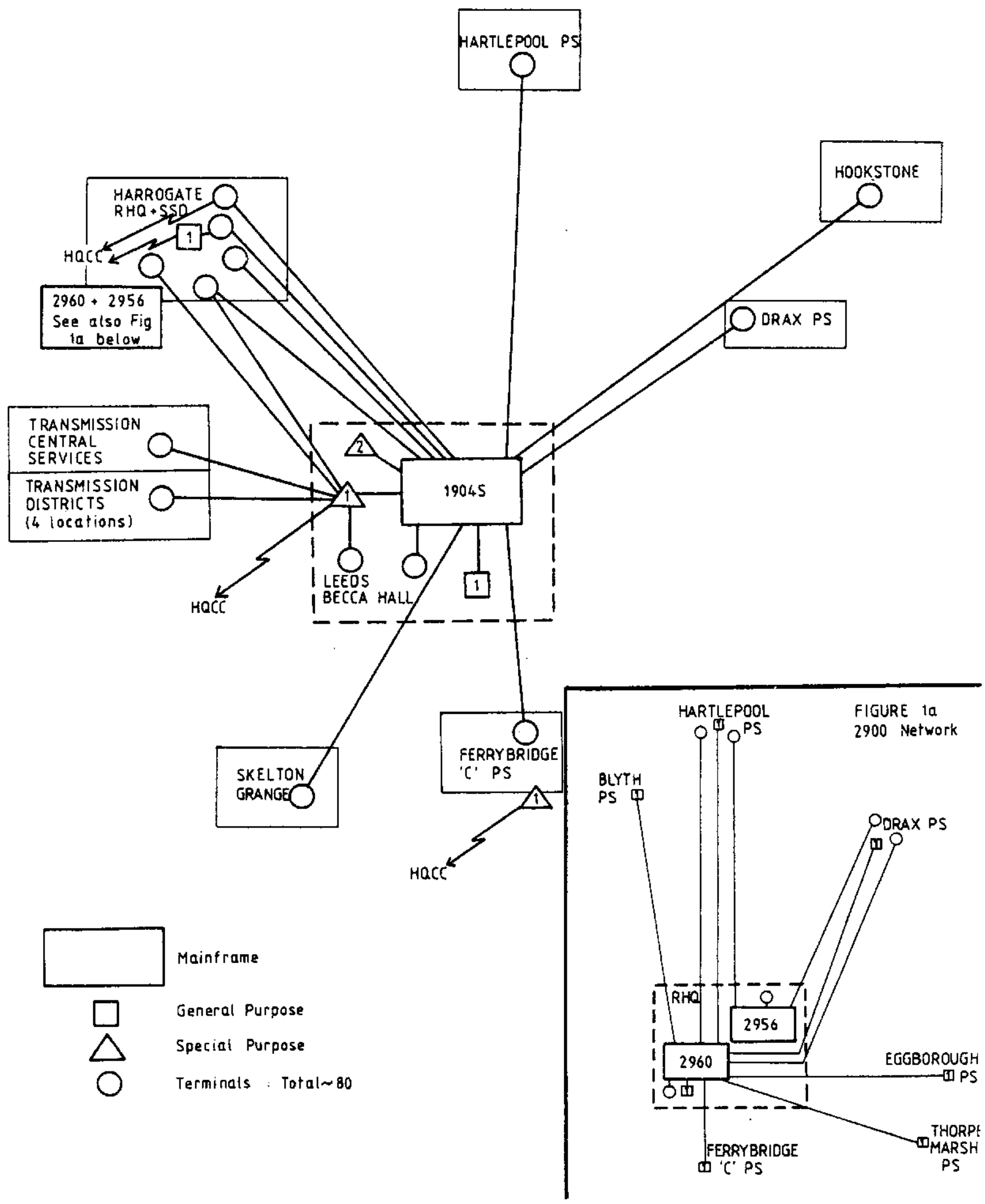
Computing Equipment—North Western Region



Source: The CEGB

FIGURE 6

Computing Equipment—North Eastern Region



Source: The CEGB

APPENDIX 23

(Referred to in paragraph 11.46)

Terms of Reference of the Systems Development Steering Group

Membership

Regional Director General (*Chairman*)
Director General
Secretary
Director of Personnel Management
Director of Finance
Director of Computing
Regional Director of Production
Regional Directors of Resource Planning
(from Regions not represented above)
Divisional Representatives as appropriate

Terms of Reference

1. To act on behalf of the CDGCO in guiding the development of management information and office systems in the Board.

2. To guide the development of other computer user system requirements when requested by the CDGCO.

3. To ensure that application developments are directed to the Board's objectives.

4. To ensure that policies and a strategy for management information and office systems are developed and that the user computer requirements are clearly defined to the Director of Computing.

5. To form detailed user groups to investigate, consider and make proposals on user requirements for systems in particular areas as necessary. To determine the terms of reference for these and to receive reports from them.

6. To consider the justification and resource requirements for projects and to propose priorities and overall timescales for development work.

7. To set up computing system projects in accordance with Computing Memorandum 2A and to appoint the Responsible Officer, Technical Officer etc for projects which encompass the responsibility of several Directors General and/or Chief Officers.

8. To report periodically to the CDGCO and to refer matters of policy when required to that Body or through it to the Executive.

APPENDIX 24

(Referred to in paragraph 12.6)

Other Functions of Barnwood

1. At the beginning of Chapter 12 the main functions of Barnwood were outlined. Other divisional functions include:

(i) providing advice to the Board on technical, commercial and project matters;

(ii) contributing to capital investment plans;

(iii) undertaking feasibility assessments for alternative development proposals;

(iv) promoting the development of plant to meet the Board's future requirements in conjunction with plant manufacturers;

(v) providing specialist technical expertise to regions on breakdowns, refits and modifications to operating plant and on civil engineering projects;

(vi) providing a commercial advisory service to other Board formations and taking the lead on behalf of the Board in developing conditions of contract and contract price adjustment arrangements with the Trade Associations;

(vii) representing the Board in collaborative arrangements in the United Kingdom and abroad, notably in the field of standards;

(viii) meeting the management, engineering and development needs of projects which have general application within the Board, such as irradiated fuel transport, nuclear decommissioning or remote inspection;

(ix) undertaking the independent design assessment required by the NII of repairs and modifications to operating nuclear plant;

(x) undertaking the requisite regular civil engineering examination of nuclear pressure vessels to determine their fitness for continued operation;

(xi) managing and engineering modifications to newly commissioned nuclear plant and preparing the associated safety documentation;

(xii) specifying national spares to the requirements of Operations Department and handling the associated commercial aspects; and

(xiii) providing resource and expertise to British Electricity International Ltd in the interests of gaining overseas business for United Kingdom industry.

Senior management

2. The Director General in charge of the division is assisted by:

Director of Plant Engineering
Commercial Director
Director of Station Design
Two Directors of Projects, one for conventional and one for nuclear stations (the Director of Station Design also acts as a Project Director).

Project organisation

3. Each Project Manager is supported by a Site Manager who leads the site organisation and by a Project Engineer who heads the project team at divisional headquarters. Contracts and accountancy staff are attached to each project team, and where there is a strong reimbursable element commercial staff are also attached to the site organisation. Both the project team and the site organisation gradually grow and then decline in size as the project progresses, the former peaking earlier. Project Managers are accountable for the total resource committed to their project. In addition to managing their own staff and under arrangements which have recently been established, Project Managers also contract for the resource they require from functional units, eg technical specialists, commercial and contract experts, and finance and accounting personnel. The allocation of resource between projects and other activities is continuously monitored to facilitate control by the Directorate.

Human resources

4. On 31 May 1980 the division's total manpower stood at 1,984 including trainees and staff seconded to other Board formations and overseas. Some 64 per cent (1,253) of these were engineering and technical staff. There were 91 management staff including Directors, 590 clerical and professional non-technical staff, and 50 industrial staff. The main breakdown was:

Construction sites	474	
Project management	586	at Barnwood headquarters
Plant engineering	265	at Barnwood headquarters
Station design (functional engineering branches)	130	at Barnwood headquarters
Commercial	151	at Barnwood headquarters
Personnel and administration (including clerical, typing and secretarial support at headquarters)	310	at Barnwood headquarters

At the end of 1979 total manpower peaked at 2,013 following a period of recruitment. During 1979 strenuous efforts had been made to recruit a select cadre of high-calibre young technical staff. This was aimed at assisting the completion of AGR stations, preparing for the expected nuclear expansion programme, and strengthening future succession arrangements in the light of the large proportion of managerial and technical staff in the 50-plus age group. The subsequent run-down in manpower from the beginning of 1980 has been achieved by freezing external recruitment in keeping with the Board's overall efforts to contain manpower levels and fixed costs. These resources have led to a further reduction in total manpower to 1,948 at 24 November 1980. The main reductions were on construction sites and in Administration.

APPENDIX 25

(Referred to in paragraph 12.22)

Power Stations Under Construction

(Note: estimated final cost at March 1980 prices = actual costs to date and March 1980 prices for future expenditure.)

Nuclear

1. *Dungeness 'B'* (2 × 600 MW)

Original completion dates (R21 and R22)	Jun 70 and Jun 71
Current assessment	Jun 81 and Apr 82
Original sanction at scheme base date prices (March 65)	£88·5 million*
Estimated increase at March 65 prices	£128·0 million*
Estimated final cost at March 65 prices	£216·5 million*
Price escalation to March 1980	£243·5 million*
Estimated final cost at March 80 prices	£460·0 million*

2. *Hartlepool* (2 × 660 MW)

Original completion dates (R1 and R2)	Feb 74 and Oct 74
Current assessment	Mar 82 and Mar 83
Original sanction at scheme base date prices (May 67)	£91·8 million*
Estimated increase at May 67 prices	£127·7 million*
Estimated final cost at May 67 prices	£219·5 million*
Price escalation to March 1980	£235·6 million*
Estimated final cost at March 80 prices	£455·1 million*

(includes substantial development costs relating to both Hartlepool and Heysham I).

3. *Heysham I* (2 × 660 MW)

Original completion dates (R1 and R2)	Mar 76 and Sep 76
Current assessment	Dec 81 and Dec 82
Original sanction at scheme base date prices (Dec 69)	£142·3 million*
Estimated increase at Dec 69 prices	£87·5 million*
Estimated final cost at Dec 69 prices	£229·8 million*
Price escalation to March 1980	£221·0 million*
Estimated final cost at March 80 prices	£450·8 million*

(Note: estimates are currently under review)

* Excluding nuclear fuel.

Conventional

4. *Grain* (5 × 660 MW)

Original completion dates (units 1 to 5)	Jan 76 to Jan 79
Current assessment: unit 2	Dec 79 (achieved)
units 1 and 3	Sep 81 and Jun 82
units 4 and 5	construction suspended
Original sanction at scheme base date prices (Dec 70)	£209·0 million
Estimated increase at Dec 70 prices	£68·8 million
Estimated final cost at Dec 70 prices	£278·7 million
Price escalation to March 1980	£295·2 million
Estimated final cost at March 80 prices	£573·9 million

So far the Board is only committed to completing the first 3 units.

5. *Ince 'B'* (2 × 500 MW)

Original completion dates (units 5 and 6)	May 77 and Nov 77
Current assessment	Dec 80 and Sep 82
Original sanction at scheme base date prices (Jan 72)	£109·5 million
Estimated increase at Jan 72 prices	£36·9 million
Estimated final cost at Jan 72 prices	£146·4 million
Price escalation to March 1980	£125·6 million
Estimated final cost at March 80 prices	£272·0 million

6. *Littlebrook 'D'* (3 × 660 MW)

Original completion dates (units 1 to 3)	Dec 79 to Dec 81
Current assessment	Dec 81 to Dec 83
Original sanction at scheme base date prices (June 73)	£183·2 million
Estimated increase at June 73 prices	£59·8 million
Estimated final cost at June 73 prices	£243·0 million
Price escalation to March 1980	£252·2 million
Estimated final cost at March 80 prices	£495·2 million

7. *Dinorwic* (6 × 300 MW) (pumped storage)

Original completion dates (units 1 to 6)	Nov 79 to Jan 81
Current assessment	May 82 to Nov 83
Original sanction at scheme base date prices (Dec 73)	£116.0 million
Estimated increase at Dec 73 prices	£66·9 million
Estimated final cost at Dec 73 prices	£182·9 million
Price escalation to March 1980	£219·1 million
Estimated final cost at March 80 prices	£402·0 million

8. *Drax completion* (3×660 MW)

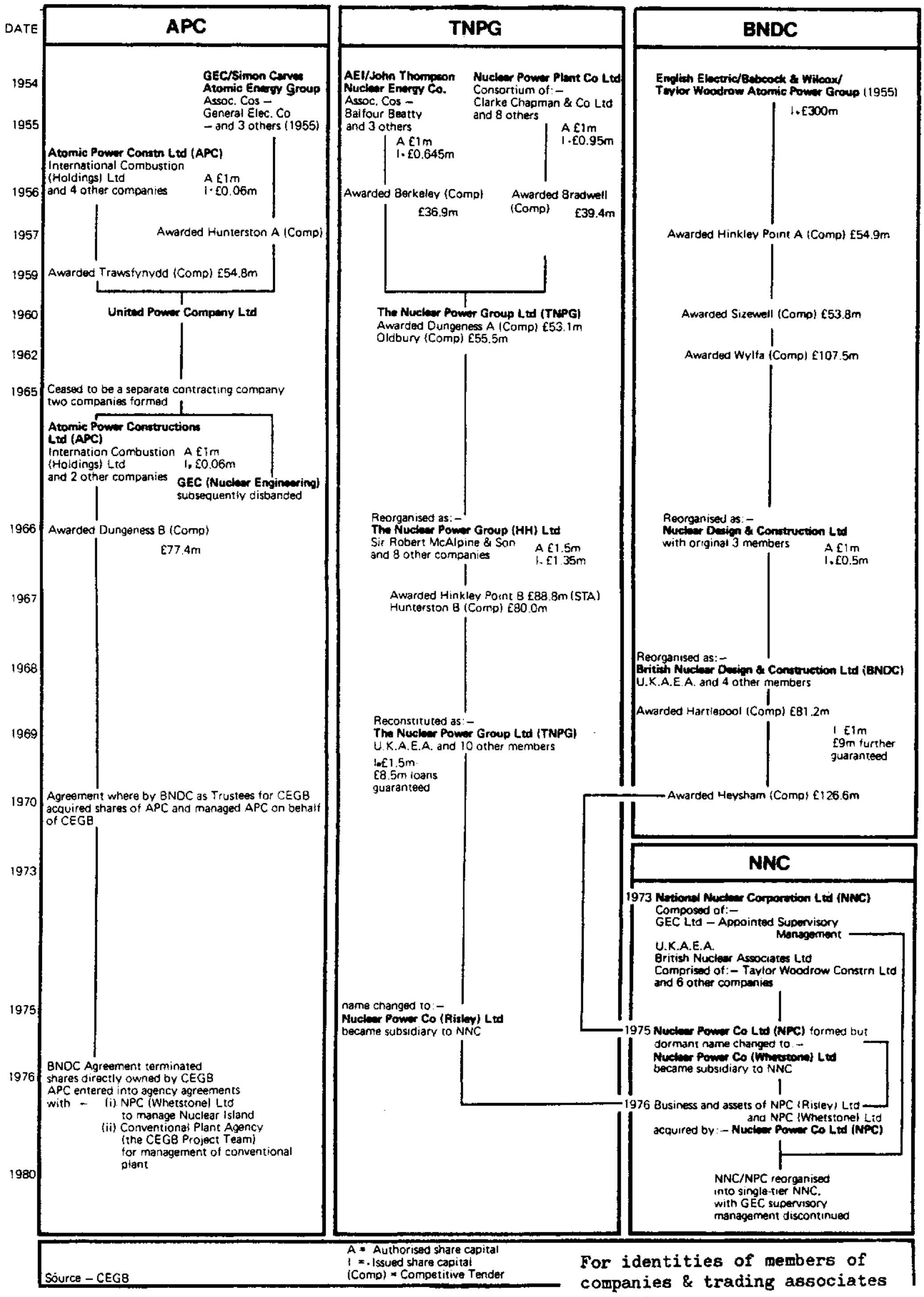
Original completion dates (units 4 to 6)	Nov 84 to Nov 86
Current assessment	Nov 84 to Nov 86
Original sanction at scheme base date prices (March 78)	£685·1 million
Estimated increase at March 78 prices	£3·7 million*
Estimated final cost at March 78 prices	£688·8 million
Price escalation to March 1980	£201·8 million
Estimated final cost at March 80 prices	£890·6 million

* This figure stems solely from changes in accounting practices.

APPENDIX 26

(Referred to in paragraph 12.93)

Amalgamations of the nuclear consortia



For identities of members of companies & trading associates see note

Identities of Members of Companies and Trading Associates

1. **APC**

(*a*) *GEC/Simon Carves Group*

Members:
General Electric Co Ltd
Simon Carves Ltd
Motherwell Bridge Eng Co Ltd
John Mowlem Co Ltd

(*b*) *Atomic Power Constructions Ltd (APC)*

Members:
International Combustion (Holdings) Ltd
Richardson Westgarth Co Ltd
Fairey Co Ltd
Crompton Parkinson (withdrew in 1961)
Nuclear Civil Constructors—(a partnership of Trollope & Colls Ltd and Holland and Hannen and Cubitts)

(*c*) *Atomic Power Constructions Ltd (APC)*

Members:
International Combustion (Holdings) Ltd
Richardson Westgarth & Co Ltd (withdrew 1966/67)
Fairey Co Ltd

2. **TNPG**

(*a*) *AEI/John Thompson Nuclear Energy Co Ltd*

Owned by AEI and John Thompson Ltd
Associated with this group (in the construction of Berkeley power station) were:
Balfour Beatty & Co Ltd
John Laing & Son Ltd
Morgan Crucible Co Ltd
Nuclear Graphite Ltd

(*b*) *The Nuclear Power Plant Co Ltd*

Shareholders:
Clarke Chapman & Co Ltd
Head Wrightson Processes Ltd
Sir Robert McAlpine & Sons Ltd
C A Parsons & Co Ltd
Whessoe Ltd
Alexander Findlay & Co
A Reyrolle & Co Ltd
Strachan & Henshaw Ltd
Parolle Electrical Co Ltd
(Parson & Reyrolle)

(c) *The Nuclear Power Group (HH) Ltd*

Members:

Sir Robert McAlpine & Sons Ltd	20%
AEI Ltd Clarke Chapman & Co Ltd Head Wrightson Processes Ltd C A Parsons & Co A Reyrolle & Co Ltd Strachan & Henshaw Ltd John Thompson Ltd Whessoe Ltd	Each with 10%

(d) *The Nuclear Power Group Ltd (TNPG)*

UKAEA	20%
Reyrolle Parsons	20%
Sir Robert McAlpine & Sons Ltd	15%
John Thompson Ltd	10%
Clarke Chapman & Co Ltd	10%
Industrial Reorganisation Corp	10% (sold 5% to Sir Robert McAlpine and 5% to Head Wrightson in March 1971)
Head Wrightson & Co Ltd	5%
Strachan & Henshaw Ltd	5%
Whessoe Ltd	5%

3. **BNDC**

(a) *English Electric/Babcock & Wilcox/Taylor Woodrow Atomic Power Group* (also called Atomic Power Projects Group)

(b) *Nuclear Design & Construction Ltd*

English Electric Co Ltd	40%
Babcock & Wilcox Ltd	40%
Taylor Woodrow Ltd	20%

(c) *British Nuclear Design & Construction Ltd* (BNDC)

UKAEA	20%
Babcock & Wilcox Ltd	25%
*English Electric Co Ltd	25%
Taylor Woodrow Construction Ltd	4%
Industrial Reorganisation Corp	26%

*Merged with The General Electric Co Ltd November 1968

4. **NNC**

National Nuclear Corporation Ltd (NNC)

Shareholding:

GEC Ltd	30%
UKAEA	35%
British Nuclear Associates Ltd	35%

British Nuclear Associates Ltd in which the shareholding is:

Taylor Woodrow Construction Ltd	14·3%
Clarke Chapman John Thompson Ltd	28·6%
Babcock & Wilcox Ltd	34·3%
Sir Robert McAlpine & Sons Ltd	7·1%
Head Wrightson & Co Ltd	8·6%
Whessoe Ltd	5·7%
Strachan & Henshaw Ltd	1·4%

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