ORKUSTOFNUN
NATIONAL ENERGY AUTHORITY

REPORT ON HVDC TRANSMISSION

FIRST REVISION

Londwatt Consultants Ltd.
20 Harcourt House
19 Cavendish Square
London W1

Virkir
Consulting Group Ltd.
Reykjavík
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OS80012/ROD06
Reykjavík, May 1980

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Iðnaðarráðuneytið
Arnarhvoli
101 Reykjavík

Útflutningur á raforku

Hjálagt sendist hinu háa ráðuneyti skýrsla um athugun sem Orkustofnun hefur látið gera á haghvæmni þess að flytja út raforku frá Íslandi til Bretlandseyja með háspenntum rakstraum. Hér er um að ræða endurskoðun á samskonar athugun, sem gerð var árið 1975. Athugunin er unnin af Londwatt Ltd., ráðgefandi verkfræðifyrirtæki í London, í samvinnu við Virki h.f., ráðgefandi verkfræðinga í Reykjavík.

Athugunin byggir á útflutningi á 2000 MW og 16.000 GWh/ári af raforku. Gert er ráð fyrir að raforkan verði flutt frá austurströnd Íslands eftir sex sæstrengjum um 950 km veg til norðurstrandar Skotlands, og þaðan eftir þremur rakstraumsháspennuloftlínum um 440 km veg suður í grennd við Glasgow, þar sem flutningsvirkin yrðu tengd við 400 kílóvolta landskerfi Bretlandseyja. Um yrði að ræða þrjár samsíða flutningsrásir, sem hver um sig flytur 667 MW. Rakspennan yrði $\pm$ 330 kílóvolt; straumurinn um 1000 amper.

Niðurstöður hagkvæmnisreikninga eru settar fram með þeim hætti, að reiknað er hve mikið raforkan megi mest kosta, komin til strandar á Íslandi, til að vera samkeppnisfær, komin inn á breska landskerfið, við raforku frá kola- eða kjarnorkustöðvum í Bretlandi. Í skýrslunni eru því gerð all-ítarleg skil, hver sé líklegur vinnslukostnaður raforku í slíkum stöðvum þar í landi í nálægri framtíð. Er álitið, að hann verði sem hér segir, reiknað í bandarískum mills á kWh (1 mill er þúsundasti hluti úr dollar):

Frá kolastöðvum	41,3 mills/kWh
Frá kjarnorkustöðvum með þrýstivatnskljúfum (PWR)	37,7 "
Frá kjarnorkustöðvum með háþróuðum gaskljúfum (AGR)	39,7 "

Grundvallar-viðmiðunin er raforkuverðið frá þrýstivatnskljúfum, 37,7 mills/kWh.

Niðurstöður athugunarinnar má í stuttu máli draga saman þannig:

- Flutningur raforku frá Íslandi til Skotlands með háspenntum rakstraum um sæstrengi virðist vera tæknilega mögulegur, en þó þyrfti áður að þróa strengi með meira togþoli en nú eru til; betri aðferðir til að leggja strenginn út; aðferðir til að grafa hann niður í hafsbotninn og til að fylgjast með þeim niðurgreftri.

- Til þess að verð raforku frá Íslandi fari ekki fram úr 37,7 mills/kWh, kominnar inn á breska 400 kV landskerfið, þ.e. til þess að hún sé samkeppnisfær við raforku frá þrýstivatnskjarnkljúfum í Bretlandi, má hún kosta í mesta lagi 14,2 mills/kWh, komin að afriðilsstöð á austurströnd Íslands, sem þannig er jafnvirðiskostnaður á Íslandi við 37,7 mills/kWh í Bretlandi.

- Næmleikagreining á áhrifum forsendna á niðurstöður gefur eftirtalda útkomu er sýnir jafnvirðiskostnað raforkunnar á Íslandi ef helstu forsendum er breytt frá því sem annars er gengið út frá í athuguninni (og gefur jafnvirðiskostnaðinn 14,2 mills/kWh):

Forsenda	Breyting	Jafnvirðiskostnaður á Íslandi mills/kWh
Stofnkostnaður flutningsvirkja	+ 30%	9,4
	- 15%	16,6
Vinnslukostnaður raforku í Bretlandi	+ 20%	20,7
	÷ 10%	10,9
Vaxtaprósenta í núgildisreikningi	Úr 10 í 12%	15,4
	Úr 10 í 8%	13,7

Allt verðlag miðast við fyrri hluta árs 1980.

Af þessu sést m.a. að jafnvirðiskostnaðurinn á Íslandi er býsna viðkvæmur fyrir breytingum á vinnslukostnaði raforku í Bretlandi. Hækki hann um t.d. 20% hækkar jafnvirðiskostnaðurinn úr 14,2 í 20,7 mills/kWh, eða um 46%.

Þetta táknar, að reynist vinnslukostnaður raforku í Bretlandi mun hærri en nú er gert ráð fyrir, t.d. sem afleiðing af vaxandi andstöðu við byggingu kjarnorkustöðva; strangari öryggiskröfum til þeirra eða launakröfum kolanámumanna umfram almennar verðlagshækkanir þar, kynni raforka frá Íslandi að ná mun betri samkeppnisaðstöðu. Á hinn bóginn er stofnkostnaður flutningsvirkjanna einkum sæstrengjanna, mikilli óvissu undirorpin, og umtalsverð hækkun hans frá því sem reiknað er með í athuguninni gæti auðveldlega eyðilagt samkeppnismöguleika íslensku raforkunnar.

- Stofnkostnaður flutningsmannvirkjanna í heild er áætlaður 2473 milljónir dollara á verðlagi fyrri hluta árs 1980 eða nálægt 1230 milljarða íslenskra króna. Gert er ráð fyrir að flutningsvirkin yrðu gerð í 3 megináföngum, og að öll framkvæmdin tæki 9 ár. Hver áfangi yrði tekinn í rekstur um leið og honum er lokið. Ofangreind stofnkostnaðartala felur ekki í sér vexti á byggingartíma.

- Talið er, að frá bresku sjónarmiði gæti innflutningur raforku frá Íslandi falið í sér þessa kosti:

1. Byggja þyrfti einni kolastöð eða kjarnorkustöð færra í Bretlandi; atriði, sem umhverfisverndarmenn á Bretlandseyjum teldu ávinning að.

2. Byggingarlóðum, sem finna þarf í Bretlandi undir stórar rafstöðvar, fækkar um eina. Nú þegar veldur það erfiðleikum þar í landi að finna lóðir undir nýjar rafstöðvar. Auðveldara er talið mundu verða að fá lóð undir áriðilsstöð í grennd við Glasgow.

3. Breskur útflutningsiðnaður á sviði hönnunar og framleiðslu sæstrengja og breytistöðva (afriðils- og áriðilsstöðva) myndi eflast við að fá svona stórt og margbrotið verkefni. Raunar má ætla að

það verði forsenda þess að Bretar fallist á innflutning raforku frá Íslandi að breskur iðnaður á þessu sviði eigi verulegan hlut að hönnun, smíði og uppsetningu flutningsvirkjanna.

4. Raforka, þar sem kostnaðarhlutdeild eldsneytis er engin er til þess fallin að hamla á móti áhrifum af síhækkandi verðlagi á kolum, olíu og kjarnorkueldsneyti.

- Aftur á móti kynnu Bretar að líta á neðantöld atriði tengd raforkuinnflutningi frá Íslandi sem ókosti:

1. Slíkur innflutningur dregur úr verkefnum fyrir breska framleiðendur á vélum og búnaði í kola- eða kjarnorkurafstöðvar. Áhrifin á atvinnuástandið í þessum iðngreinum til skemmri og lengri tíma litið gætu vel valdið óánægju.

2. Innflutningur frá Íslandi táknar frekar aðfærslu á raforku inn á kerfi þar sem vinnslugetan er nú þegar verulega umfram eftirspurn (uppsett afl er sem stendur um 35% meira en mesta álag).

3. Ekki er um að ræða möguleika á orkuskiptum, þ.e. flutningi í báðar áttir á mismunandi tímum, þannig að sá ávinningur sem fylgir samtengingum sem ætlaðar eru fyrir orkuskipti og stafar af því að álagstoppar falla ekki saman; heildaraflþörf verður minni; samtengdu svæðin geta hjálpað hvort öðru í bilanatilvikum o.s.frv., er ekki fyrir hendi í þessu tilviki. (Til þess er íslenska raforkukerfið allt of lítið)

4. Vafi leikur á hversu öruggur er flutningur raforku um 1000 km sæstrengi, og þessi vafi verður fyrir hendi uns frekari reynslu hefur verið aflað af svipuðum orkuflutningu annarsstaðar.

5. Rakstraums- háspennuloftlínurnar munu liggja um þrjá fjórðu af lengd Skotlands. Erfiðleikum er nú þegar bundið að fá landrými undir háspennulínur, og loftlínur sem þessar kunna að mæta mikilli andstöðu frá umhverfissjónarmiði.

Ekki liggur ljóst fyrir hvert yrði kostnaðarverð íslenskrar raforku, kominnar til strandar austanlands, t.d. á Reyðarfirði. Meginhluti þeirra 16000 GWh/ári sem rætt er um að flytja út gæti komið frá virkjunum í Jökulsá á Brú. Orkustofnun er þeirrar skoðunar, að væntanlegur munur á þeim kostnaði og 14,2 mills/kWh sé of lítill til að vera verulega áhugaverður þegar tekið er tillit til þeirrar miklu óvissu sem tengd er útflutningi sem þessum, bæði varðandi vinnslukostnað raforku í Bretlandi og stofnkostnað flutningsvirkjanna. Væntanleg hagkvæmni raforkuútflutnings frá Íslandi til Bretlands verður þannig að teljast vera svo nálægt núllmarkinu þegar á allt er litið að ekki sé sem stendur tilefni til frekari aðgerða í málinu. Hins vegar er rétt að fylgjast áfram með þróuninni í þessum efnum og gera nýjan samanburð að hæfilegum tíma liðnum eða strax og vart kynni að verða verulegrar hækkunar á vinnslukostnaði raforku í Bretlandi frá því sem gert er ráð fyrir í athugun þessari.

Allra virðingarfyllst,

Jakob Björnsson

Letter of Presentation to the
Ministry for Industry
by the National Energy Authority

July 23rd 1980

Electric Power Export from Iceland

Enclosed we are presenting to the Honoured Ministry for Industry a report on a study undertaken under the auspices of the National Energy Authority of the technical and economic feasibility of exporting electric power from Iceland via a HVDC submarine link to the United Kingdom. The report is a revision of a similar study undertaken in 1975. The study was performed for the National Energy Authority by a London-based consulting engineering firm, Londwatt, Ltd, in cooperation with Virkir Ltd, Consulting Engineers, Reykjavík.

The Study is based on an export of 2000 MW and 16 000 GWh/year of power. The transmission is assumed to take place form the east coast of Iceland via six submarine cables over a distance of 950 km to the north coast of Scotland in the neighbourhood of Cape Wrath, and thence over three 440 km HVDC overhead lines down to the Glasgow area, where the linke would be connected via a converter station to the U.K. 400 kV National Grid. There would be three parallel transission circuits, each transmitting 667 MW. The DC voltage would be $\pm$ 330 kV and the DC current approximately 1000 amperes.

The results of the economic feasibility study are presented in the form of a minimum or break-even cost for Icelandic power, at the AC busbars of the converter station on the Icelandic side for it to be competitive, at the AC busbars of the U.K. converter station, with coal and nuclear generated power in the U.K. The report discusses to a considerable extent the probable near-term production cost of electricity from coal-fired and nuclear power stations in the United Kingdom. It is expected to be as follows, expressed in U.S. mills per kWh (1 mill is one thousandth of a dollar):

From coal-fired plants	41.3 mills/kWh
From nuclear plants, PWR	37.7 "
From nuclear plants, AGR	39.7 "

The basis for the study is taken as 37.7 mills/kWh, the expected cost of PWR nuclear power.

The principal results of the study may be summerized as follows:

- Transmission of electricity from Iceland to the U.K. via a HVDC submarine link appears technically feasible, even though some development work should be expected for cable tensile strengthening and cable lying, burial and burial surveillance.
- The break-even cost at the AC busbars of the Icelandic converter station of Icelandic power is 14.2 mills/kWh, based on an assumed cost of nuclear generated electricity in the U.K. of 37.7 mills/kWh.
- A sensitivity analysis of the effects on the results of a variation in the values of the basic variables in the study reveals the following:

Variable	Variation	Break-even cost in Iceland mills/kWh
Cable and Line Cost	+30%	9.4
	-15%	16.6
U.K. Generation Cost	+20%	20.7
	-10%	10.9
Discount Rate	From 10 to 12%	15.4
	From 10 to 8%	13.7
Base value	None	14.2

All costs are based on early 1980 price level

The sensitivity analysis clearly shows that the break-even cost in Iceland is fairly sensitive to variations in U.K. generation cost. Thus, ca. 20% increase in this cost raises the Icelandic break-even cost from 14.2 to 20.7 mills/kWh, or by 46%.

This means that should the generation cost of electricity in the United Kingdom turn out to be appreciabley higher than assumed in the study, as a result of for instance increased public opposition to nucleas power; more stringent safety requirements for nuclear plants or wage claims by coal-mine workers over and above the general rate of inflation in the U.K., the competiveness of power imported from Iceland might be appreciably enhanced. On the other hand, the construction cost of the transmission facilities, especially the submarine cables, is subject to considerable uncertainty, so that a marked increase in this cost over the level assumed in the study could nullify a calculated economic benefit of the scheme.

- The total construction cost of the transmission scheme is estimated at \$2473 million at the early 1980 price level, or approximately Icelandic krónur 1230 billion (10^9). The scheme is assumed to be constructed in three stages, or circuits, and the construction would extend over a period of 9 years. Each circuit would be put into operation as soon as it is finished.
- It is concluded that from a U.K. viewpoint the HVDC scheme could provide the following advantages, apart from its economics:

  1. The displacement of fossil fuel burning or reactor powered generation would be attractive to environmentalists.
  2. One less large power station site would be needed. With the current U.K. generation programme, problems are being experienced in obtaining new sites. A converter station is expected to present less of a problem.
  3. The U.K. export-oriented industries associated with converter equipment and cable design and manufacture would be boasted by the involvement in a scheme of this magnitude and complexity. In fact, the involvement of British industry in the design, manufacture and construction can be expected to be a prerequisite for acceptance of the scheme.
  4. An electricity source with a negligible fuel cost content would provide a counter to ever-increasing coal, oil and nuclear fuel costs.

- On the other hand, the following problems associated with the scheme may be foreseen, again apart from economics:

  1. Acceptance of an energy input which would displace activities from the U.K. manufacturing and energy supply markets. The deleterious effect on short and long term employment could be unpopular.
  2. A further input of electricity to a system which has already a surfeit of generation capability (i.e. a spare plant margin of around 35% at present).
  3. Lack of apportunity for reciprocal energy exchanges, so the benefits of diversity, reduced total plant requirements and mitigation of operating problems cannot be realised to the extent possible with an

exchange scheme (the Icelandic power system is far too weak for meaningful reciprocal exchanges)

4. Doubts about the security of a 1000 km undersea transmission link may exist until more performance data on comparable schemes is collected.

5. Overhead HVDC lines would need to traverse about three-fourths of the length of Scotland. Transmission line way-leaves are difficult to obtain and a link such as this could meet strong environmental objections.

The cost of Icelandic hydro-generated electricity at the east-coast, Reyðarfjörður for instance, is at present somewhat uncertain. A substantial part of the 16000 GWh/year involved in the export-scheme could come from plants on the Jökulsá á Brú River close to the coast, which are expected to be very economical plants, even if their costs are still not well known. However, in view of the National Energy Authority, the expected difference between these costs and the break-even cost of 14.2 mills/kWh is too small to be of great interest when considering the very substantial uncertainties associated with the export scheme, both regarding U.K. generating costs and the construction costs. In other words, the economics of the scheme is quite marginal and, taking the uncertainties into account, too marginal to warant further consideration for the time being. However, developments of HVDC underseas transmission technology should be monitored as well as U.K. generating costs, and a new study undertaken when appropriate, especially if U.K. generating costs should rise appreciabley above the level assumed here.

Yours respectfully,

Jakob Björnsson

Jakob Björnsson
Director General
National Energy Authority

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SUMMARY

In this report, the technical and economic aspects of the export of bulk electrical energy from Iceland to the United Kingdom are examined. The study performed by Londwatt and Virkir in early 1975 has been revised to take into account technological developments in HVDC transmission and policy changes affecting base load generation in the U.K.

While the scheme to export hydro generated electricity from Iceland is technically feasible, many complications are presented in selecting a suitable undersea cable route. Oceanographic conditions between Iceland and Scotland are not conducive to simple power cable laying and the route length is far greater than that of any existing submarine cable. In addition, cable would have to be laid in water depths of approximately 1000 m which is twice as deep as that encountered in any existing HVDC scheme.

For the scheme to be economically viable, i.e. to produce cheaper electricity than base load generation in the U.K., electrical energy delivered to the AC busbars of the converter station in Iceland would have to cost less than 14 US mills/kWh, based on the equipment prices established in this Report.

1. INTRODUCTION

1.1 Original Report

In April 1975, Londwatt Consultants Ltd and Virkir Associated Engineering Consultants Ltd prepared for the National Energy Authority of Iceland (NEA) a report on the viability of a power link between Iceland and Scotland.

The pre-feasibility study included an examination of the technical and economic aspects of a unidirectional high voltage direct current (HVDC) link between the countries in order to utilise part of the extensive hydro electricity potential in Iceland. The generation source in Iceland was nominated by NEA to produce 2000 MW with an output of 16 TWh per annum.

As well as examining the basic technical requirements for this scheme, including AC/DC converter stations in the two countries, undersea HVDC cables and overhead transmission lines, the report provided an assessment of the maximum allowable cost of generation at the converter station AC busbars in Iceland to make the scheme economically acceptable. For the conditions prevailing in early 1975, it appeared that electricity total production costs would need to be between 7 and 16 US mills/KWh, depending on whether a pessimistic or optimistic view was taken of displaced nuclear generation plant programmes in the United Kingdom.

The report showed also that the scheme was technically realistic, but cable routing would be a problem. No HVDC scheme had ever been undertaken where cables had to span such great distances or be laid in such deep waters.

1.2 Terms of Reference for Revision

Since the original report was prepared, there have been developments in HVDC scheme technology, national generation programmes have been modified and both capital plant and fuel costs have changed.

In late 1979, the NEA of Iceland commissioned Londwatt and Virkir to reassess the proposed Iceland to Scotland scheme in the light of technical and cost movements. The Terms of Reference for this First Revision are as follows:

1. Revision and evaluation of the basic cost of energy production by nuclear and coal-fired power plants, taking into account current U.K. policies and possible future developments.

2. Revision of the costing of the 2000 MW undersea HVDC link, including terminal equipment and cables.

3. Revision of the economic comparison of the schemes delivering energy by HVDC and U.K. based generation.

4. Basic appraisal of technological developments in so far as they affect item 2 above.

A 2000 MW rectifier station would be located in Iceland. Cables would be used for the sea crossing to Scotland where the transmission to the inverter station, at a suitable load centre, would continue by overhead line.

1.3 Methodology for the Study

In order to provide a sound basis for the HVDC scheme's technical evaluation and costing, the latest developments and comparable schemes have been examined using data provided by Scandinavian, British and Continental manufacturers as well as information published in the technical literature.

Without making a formal approach to the electricity generation authorities in Britain, medium term development plans for generation and transmission have been assessed. Included in this was an examination of power station future fuelling trends.

For generation plant pertinent only to the U.K., budgetary costs based on current data have been derived. For generation plant hitherto unused in the U.K., costing has been based on international figures, weighted in accordance with possible requirements relevant to the U.K.

As the technical features for the HVDC link include a high load factor of 91.3%, it would constitute a base load bulk transmission scheme. Consequently the economic appraisal of the scheme has been centred on the displacement, at a common point, of the equivalent amount of base load energy generation in the U.K. For the HVDC scheme to be viable, the cost of Icelandic generation, annuitised with both 'fixed' and 'running' components, should be below the calculated break-even value.

In the economic analysis of the scheme, a generally optimistic attitude to U.K. generation costs and construction programmes has been assumed while a cautious attitude to the HVDC scheme has been adopted. Consequently, any unforseen development cost increases or station construction postponements and delays in the U.K. generation programme will bias the costs in favour of the HVDC scheme.

1.4 Assumptions

As the calculated cost of generation in Iceland applies to the EHV AC busbars of the converter station in Iceland, no allowance has been made for the costs of transmission from the generation source to the converter station. The voltage of the converter station busbars has been taken to be 220 kV. In addition, it has been assumed that the converter station would be located on the south east coast of Iceland, near latitude 65^{o}.

The rate of build-up of generation capability in Iceland would not be less than that required by the commissioning programme for the HVDC link.

Budgetary costs are relevant to early 1980 and the following exchange rates have been used:

Currency	Equivalent for £1 Sterling
U.S. Dollar	2.2
Swedish Crown	9.7
Norwegian Crown	11.3
Icelandic Crown	1050
Swiss Franc	3.9

All costing in the study has used USA dollars.

The opportunity cost of capital has been taken to be 10% pa and discounting has been performed using this rate. Sensitivity analyses have used rates of 8% and 12% pa.

2. APPRAISAL OF HVDC CONVERTER TECHNOLOGY

2.1 Review of Principles and Parameters

2.1.1 General

Where two AC systems or power sources are interconnected by a DC link, the converter stations at each end of the DC link contain

- converter bridges, with controls, to rectify from AC to DC or invert from DC to AC
- tap-changing converter transformers to isolate AC and DC, obtain optimal nominal voltage levels and provide coarse control of working voltage
- reactive power sources for the converters
- harmonic filters and smoothing reactors
- ancillary systems

In this context, a link comprises the transmission cable or overhead line together with the converter stations.

Both magnitude and direction of power flow through the link are controlled by delaying the start of the conduction period of the converting devices at each end. This control over the 'gating' or 'firing' of the converters permits the ratio of mean DC voltage to rms AC voltage to be varied in magnitude and sign.

Descriptions of the operation of each element and a scheme were included in the original report of April 1975.

2.1.2 HVDC Capabilities

Offsetting the complexity and high cost of AC/DC conversion equipment are the following scheme advantages. While the decision to proceed with an HVDC project may be based on one of these factors, as listed, supplementary benefits from some of the other features can often be achieved.

- AC systems, interconnected by an HVDC link only, operate asynchronously with neither system contributing to the fault level of the other.

- Long distance bulk power transmission may be obtained more economically with HVDC than with a scheme employing alternating current.

- Difficulties in obtaining wayleaves for overhead lines feeding high load density areas can be minimised by using high rated DC cable circuits which can be buried. AC fault levels in the load area will, of course, be kept at existing levels.

- With bidirectional DC links, reserve plant can be shared between the two systems, thereby minimising total installed capacity, without worsening stability and fault performance.

- Dynamic performance of an AC system under fault can be improved with judicious selection of converter controls at a DC infeed or DC circuit in parallel with an AC circuit.

In some situations, such as this unidirectional link between Iceland and Scotland, electrical power transmission is possible only with DC. The high level of capacitive charging current for an AC cable precludes the use of a cabled EHV AC system over distances greater than approximately 50 km.

2.1.3 Valve Types and Configuration

A three phase system can be transposed to multi phase operation by the judicious selection of transformer winding vector groups.

In the process of conversion between AC and DC, the greater the number of AC phases contributing to the DC voltage, the higher will be the mean DC voltage capability and the lower will be the total harmonic content. For high power installations, the choice has been usually between 6 and 12 pulse operation. Schemes employing mercury arc rectifiers have usually adopted the 6 pulse per pole configuration due to insulation problems and the high cost of rectifier transformers.

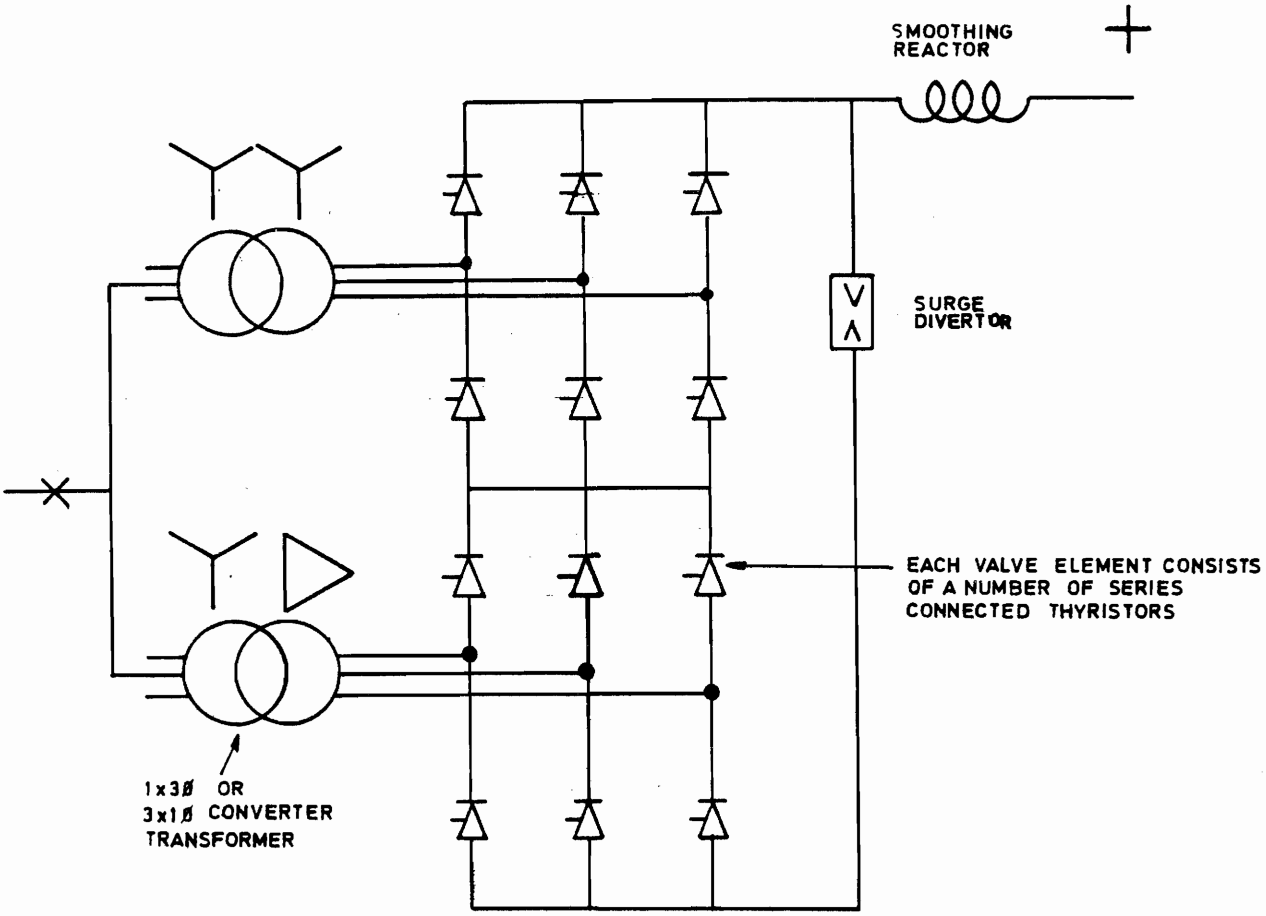
Semi-conducting thyristors have provided an enhanced opportunity to employ 12 pulse operation. A schematic representation of a typical 12 pulse group using the double Graetz circuit is shown in Figure 2.1. With this arrangement, the 5th and 7th harmonics present in 6 pulse operation are virtually eliminated from the AC side, leaving only 11th, 13th and higher order characteristic harmonics in the series ($12n \pm 1$). On the DC side, 12th multiple characteristic harmonics are present. Harmonics generate losses and interfere with communication circuits. Filtering for the AC harmonics, at least, is required in each HVDC scheme.

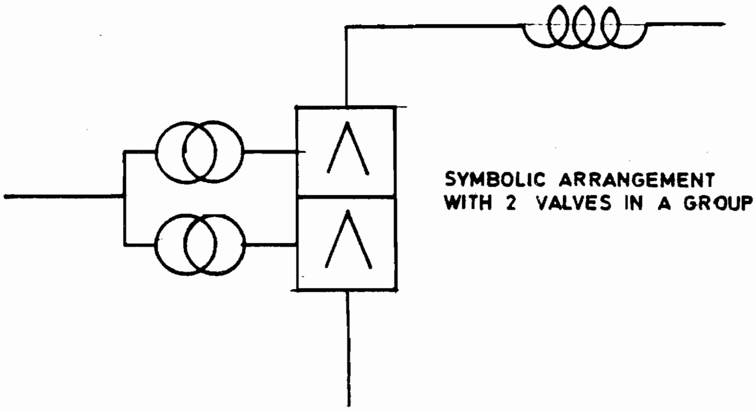
Although more converter transformers are required for 12 pulse operation, the reduced filtering requirements, loss reductions and transformer design improvements have meant that the 12 pulse arrangement with thyristors is cheaper.

A significant advantage offered by thyristor valves is that converter voltages can be selected to suit extraneous requirements, such as a cable voltage rating. As thyristor valves are made in modular form and employ a large number of series connected low voltage rated devices, there is less need for the voltage standardisation which is characteristic of AC systems.

Undersea cable capabilities will govern the plant arrangements which are suitable for this HVDC system. Many combinations of valve groups are possible and some of the arrangements are sketched in Part 3.4.4 of this report. To achieve maximum economies in the converter stations, the highest feasible current ratings and the minimum number of valve groups should be adopted.

FIG 2.1 TYPICAL 12 PULSE GROUP USING THYRISTORS





2.1.4 Reactive Power Requirements

Both rectifiers and inverters consume reactive power. Some of this need can be met by static capacitors in the harmonic filters and some from the AC network. The balance must be provided by additional static capacitors or, if busbar voltage levels are to be controlled rapidly, by synchronous condensers or static compensators.

By keeping the rectifier valve firing control angle (α) and inverter extinction angle (γ) low, variations in harmonic content and the ratio of reactive to active power can be kept to a minimum. Consequently plant cost and losses can be kept down. As a general indication, reactive power requirements are approximately half the rated active power level at a converter station.

In a region of high fault level, the existing AC system may provide an adequate reactive power source. However, detailed studies are necessary to establish the reactive power needs based on AC system stabilisation and filter capacitor requirements. By locating the inverter station where fault levels are reasonably high, i.e. in a high power density area, there may be no need to install synchronous condensers or static compensators. System capability should then be adequate to control inverter station voltage levels and maintain DC power transmission during periods of AC system severe disturbance. For example, a fault level of approximately 5000 MVA could be sufficient for a received DC power level of 2000 MW.

2.1.5 New Schemes

Interest in and the size of HVDC schemes is increasing. Part of this greater interest is due to the wider application of HVDC as an aid to EHV AC system stability control.

Basic data on recent and planned large HVDC schemes are set out in Table 2.1. All except Nelson River 1 employ thyristor valves.

Table 2.1

Recent and Planned HVDC Schemes

LOCATION	POWER MW	VOLTAGE kV	PURPOSE
Skagerrak - Norway/Denmark	500	$\pm$ 250	Undersea interchange
Nelson River 1 - Canada	1620	$\pm$ 450	Long distance transmission, & AC stability
CU - USA	1000	$\pm$ 400	Long distance trans, stability & environment
Nelson River 2 - Canada	1800	$\pm$ 500	Long distance transmission & stability
Stegall - USA	100	2 x 25	Back-to-back
Square Butte - USA	500	$\pm$ 250	Long distance transmission
Cabora Bassa - Mozambique/S.Africa	960/1920	$\pm$ 533	Long distance transmission
Inga Shaba - Zaire	560/1120	$\pm$ 500	Long distance transmission
Cross Channel - France/England	2000	$\pm$ 270	Undersea interchange
Shin Shinano - Japan	300	2 x 125	Back-to-back
Hokkaido Honshu - Japan	600	$\pm$ 125	Undersea transmission
Itaipu - Brazil	6300	$\pm$ 600	Long distance trans & frequency difference
Finland/USSR		$\pm$ 110	Back-to-back
Ekibastuz/Centre - USSR	6000	$\pm$ 750	Long distance transmission
Austria/Czechoslavakia	550	$\pm$ 160	Back-to-back interchange & bulk transmission

2.2 Converter Station Developments

2.2.1 Plant Items

The general items of plant listed in 2.1.1 comprise conventional AC plant as well as plant specific to AC/DC conversion. In the following sections reference is made to the principal developments in plant technology over the last 5 years.

While most improvements have occurred with conversion plant, some gains have been reaped from advances in conventional AC switchyard capabilities.

2.2.2 Thyristors

For new schemes or the augmentation of existing schemes, thyristors have virtually supplanted mercury arc valves as the conversion devices. The main advantages offered by thyristors over mercury arc valves are:

- reduced station dimensions
- cheaper valve and auxiliary equipment costs
- modular valve construction with inbuilt redundancy
- composite voltage grading of thyristor assemblies and auxiliary power inputs
- reduced maintenance requirements
- increased reliability
- improved performance characteristics, including freedom from arc-back

Research and development have concentrated on improving thyristor power performance and control circuits. Although there has been some increase in thyristor voltage blocking capabilities, the most noteable improvements have been in current-carrying capabilities using larger area semi-conducting wafers. Some thyristors are able to carry continuous currents in excess of 3000 A. As a result, there is little need to operate units in parallel to achieve full pole currents so the number of devices per pole, including associated controls, can be kept to a minimum. Series thyristors employ working voltages of approximately 1.5 kV each, with rated blocking voltages up to approximately 4 kV.

As a general indication, higher current levels will result in lower converter station costs for a given power transmission requirement. For thyristors with ratings above 1500 A approximately, water cooling of the valves is usually employed. The quality and reliability of water cooling systems is considered to be quite high.

Reference to thyristor redundancy is made in Part 2.3.2.

Improvements in valve, transformer and filter designs have resulted in a decrease in converter station losses. A typical figure of 2% full load losses, including auxiliary power requirements, covering both rectifier and inverter stations can be applied to a scheme of this size. These losses are divided almost evenly between converter transformers and the rest of the plant. Consequently, for this 2000 MW scheme, converter station losses will amount to 40 MW approximately.

2.2.3 Protection and Control

One recent technological development which will be important to this scheme is the advent of the non-gapped zinc oxide surge diverter. Conventional gapped diverters would be hard pressed to handle the high discharge currents of the long DC cables. The new diverters should be adequate.

The precise characteristics of zinc oxide diverters should permit basic insulation levels to be reduced.

While the basic control of a DC transmission link is via current at the sending (rectifier) end and voltage at the receiving end plus current margin between ends, the application of more complex controls has increased. DC link control can employ either:

- constant power transmission
- constant current/extinction angle
- constant receiving system frequency
- constant AC system power factor
- AC system stabilisation (damping)

An HVDC link can function reliably with separate but coordinated controls at each end, i.e. with no communication link. However, for rapid system start up after shut down and enhanced control over the performance of the connected AC system, a reliable high speed communication link between the two ends is needed. As well as transferring system data to the master station, control instructions can be automatically and simulatenously set up at each end.

Controls and auxiliary supplies can be provided with sufficient security (i.e. redundant mode) so that failure of one pole will not interrupt or curtail the performance of any other pole in the converter station.

With mercury arc valves, problems were experienced in the control of valve firing as auxiliary transformers required insulation for high voltages. The commonly used technique with thyristor valves is to draw auxiliary power from the thyristor external grading circuits which are used to proportion voltage stress over the thyristor assembly. Light guides are used to transmit control signals to these auxiliary circuits at valve voltage. This development has resulted in improved valve reliability.

Although not required for this scheme, development work is continuing with the aim of producing a satisfactory HVDC circuit breaker. The main application for DC circuit breakers will be in multi-terminal schemes.

2.2.4 Static Compensation

Traditionally, synchronous compensators have been used to provide rapid (approximately 500 msec overall response time) and continuous control of converter station AC busbars in all but the strongest (low impedance) AC systems. These rotating machines are expensive and require regular maintenance.

It is likely that more use will be made of static compensators which are cheaper and provide an even more rapid control of voltage. Overall response times down to 10 msec can be obtained. Static compensators comprise elements of static capacitance and reactance plus control of their relative contribution to the overall MVAr level. Reactive power capability can be varied from generation to absorption. A significant advantage is that they do not contribute to the fault level, whereas a synchronous compensator can supply fault currents approximately 4 to 6 times its rating.

Some static compensators employ a controllable saturable reactor with harmonic compensation. Consequently an almost sinusoidal fundamental waveform of current is produced. As with synchronous compensators, a voltage transformer is required for connection to an EHV busbar.

Another type of static compensator employs thyristors to switch, in a controlled mode, a high inductive impedance. This switched inductance, in association with static capacitors connected in parallel with it, provides a controllable reactive power source. Although primarily intended for rapid voltage control as a stability aid on EHV AC systems, the arrangement is applicable to AC busbar control in converter stations.

A further type employs a reactor in parallel with thyristor switched capacitors.

2.2.5 Compact Stations

Particularly for locations where station siting is difficult, interest is growing in the use of compact stations using SF_6 gas-insulated metal-enclosed busbars and components. Gas insulation for valves has not been promoted actively as water and air cooling methods are well established.

While gas-insulation is commonly employed now in EHV AC installations, its application to HVDC is already considered satisfactory for voltages up to $\pm$ 400 kV.

Substantial reductions in station size could be achieved if static capacitors were to be gas insulated. Some developmental work is in progress in this area.

2.3 Station Reliability

2.3.1 Plant Performance

With the advent of the high-rated thyristor and better control circuits, converter station reliability has been improved. Factors which have contributed to this improvement are in-built redundancy of thyristor strings and redundancy in the design of auxiliary supply and control circuits. A failed thyristor provides an effective path for normal or fault current flow so converter operation can continue unimpeded provided the redundancy margin (see 2.3.2) has not been used. Under these latter circumstances, voltage stressing of individual thyristors increases to nominal design values.

The available long-term averaged statistics on converter station availability do not yet distinguish between mercury-arc valves and thyristor valves. 'Availability' is described in the Definition of Terms appended to this report. While overall figures show a typical availability of better than 98%, general comments indicate that thyristor valve availability is considerably better than that for mercury-arc valves. It should be borne in mind that this quoted availability includes both HVDC and conventional EHV AC plant in the converter station, but does not include outages for maintenance, repair or testing. (Conventionally, 'availability' includes a component for scheduled outages, as well as those which are unscheduled, or forced).

Based on operating experience, the expected failure rate of a 12 pulse thyristor valve group is approximately 0.05 per year, compared with a slightly lower value for power transformers. Unlike power transformers, however, valve outage time for repairs is short, being only part of a day, as automatic monitoring and modular construction permit easy identification and removal of the faulty unit.

From manufacturers' figures for thyristor converters plus other HV plant and auxiliary systems, availability for a complete bipole (rectifier and inverter stations) is expected to be approximately 99.8% for forced outages. This assumes a spare converter transformer is available at each station.

2.3.2 Plant Maintenance

Maintenance requirements for the conventional AC equipment in a converter station are already well established by individual power authorities. Most maintenance work in a converter station is governed by AC plant, such as HV circuit breakers, transformer tap-changers, etc.

Valve maintenance is required every one to two years, when control, auxiliary and cooling systems are checked and suspect or faulty thyristor modules replaced. This work takes less than one week for a valve group.

To keep converter station maintenance infrequent (e.g. 2 yearly), approximately 3% redundancy of thyristors is designed into the valves. With this value, an operator can be reasonably confident that thyristor failure will not cause forced outages. Should an excessive number of failures in a module occur, however, automatic monitoring will provide an operator with sufficient warning to prepare for a hurried scheduled outage.

2.3.3 Overall Availability

When 'unavailability' for scheduled (e.g. maintenance) outages is added to the unavailability due to forced outages, a total of approximately 1½ to 2% is obtained, i.e. an overall availability of approximately 98%.

2.4 Plant Requirements for Scheme

2.4.1 Plant Arrangement

Adopting a conservative approach to supply reliability, as further explained in Part 3.4.4, the AC and DC arrangement proposed for the two converter stations is shown in Figure 2.2. The "1½ circuit breaker" arrangement is suggested for a high level of security.

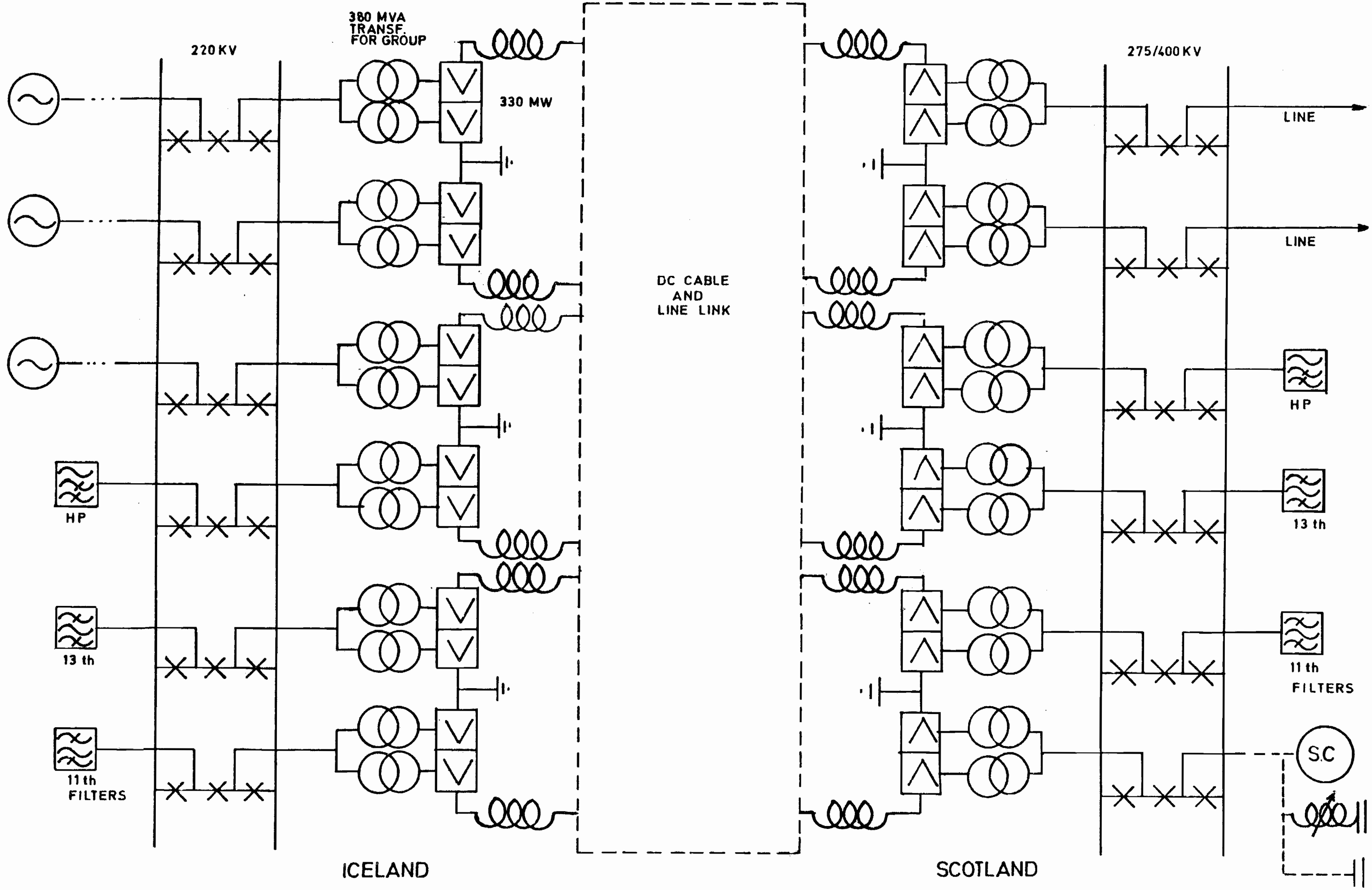
As well as AC filters (11, 13th harmonic and high pass) at the inverter station, a source of controllable reactive power has been shown tentatively. In the costing of the scheme, it has been assumed that the receiving-end busbars would be 400 kV, or 275 kV and near the 400 kV system, and no such compensation would be required.

If generators are to be used specifically for the HVDC scheme, the harmonic filters at the rectifier station may not be needed as generator windings could be designed for harmonic control.

Switching, bypassing, and surge diverting requirements have not been shown. Nor has DC shunt filtering been included as the parameters of the DC transmission link may not require it. Only a detailed system analysis will show whether or not this extra filtering is necessary.

Although transformer reliability has been increasing over the years and the absence of arc-back phenomena with thyristors means that short-duration transient over-voltage stressing of transformer insulation is reduced, any outage of a converter transformer would mean an extended supply loss for the valve group concerned. It is suggested therefore that a spare transformer be available on site at each converter station. Basic transformer design, i.e. whether single or three phase and/or 2 or 3 winding type, would be influenced by the requirement of the spare transformer to take the place of any vector group transformer in the station.

FIG 2.2 POSSIBLE TERMINAL STATION ARRANGEMENT



Transport weight will be a limitation to converter transformer rating. Within Britain, it is necessary to change from three phase to single phase construction for units above 300 MVA approximately.

On the basis that extended monopolar operation will not be allowed, earth electrodes need only be dimensioned for intermittent operation.

2.4.2 Faeroe Islands Station

A small teed connection supply to the Faeroe Islands is feasible, although the specific cost ($/kW) of conversion equipment will be high owing to the need to over-rate the equipment to meet the main system DC voltage and surge current conditions.

Either a parallel or series arrangement could be used. Even though a series arrangement offers the benefit of reduced voltage rating, a parallel arrangement is preferred as failure of the cable between Iceland and the Faeroes would permit supply to be taken via a DC tie in Scotland after the faulty cable had been isolated. In this case, an HVDC circuit breaker in the tee would be advantageous as a fault in the small (parallel) converter station would permit the main link between Iceland and Scotland to operate with negligible disturbance during the fault. Without such a circuit breaker, pole current would have to be reduced to zero, by thyristor control, until fast-acting isolators disconnected the tee-off station.

If this arrangement were to be effected at some time after the main scheme commissioning, the cable nearest to the Faeroe Islands could be cut and jointed sections led into the Island. Isolation facilities would be provided at the DC busbar on the Faeroes.

It is assumed that a tee-off to the Faeroe Islands would not be required if the 60 MW single cable HVDC link between Iceland and Faeroes were to be installed in the near future.

2.4.3 Communications

As high attenuation in the DC cables would preclude the possibility of power line carrier communications between the two ends, it is proposed that a high speed link using, for example, two 1200 baud data channels be provided by satellite. It is understood that an earth station associated with a synchronous satellite over the North Atlantic is to be established soon in Iceland. Such a link should provide higher security than the existing undersea telecommunication cable. Naturally, a link between the land station in Iceland and the HVDC converter station would have to be established.

A secure communication link would be required for load despatching, as well as for converter control.

2.4.4 Construction Requirements

Design and construction of a converter station take, in all, approximately 3 years.

As sections of the scheme should be commissioned as quickly as possible, and a considerable period of time would be involved in manufacturing and laying the cables, it is expected that the project would be commissioned as each bipole is completed, i.e. in 3 stages.

If monopolar operation were allowed by the UK authorities (Ref. 3.4.3), a 6 stage programme would be possible and maximum use could be made of each cable as soon as laid.

2.5 Converter Station Costing

2.5.1 Unit Costs

Costs of modern converter stations were obtained from Scandinavian, British and Continental manufacturers. The costs quoted in this report represent an amalgam of the individual budgetary figures.

In real money terms, there has been a decrease in converter station specific costs over the last 5 years, in spite of cost increases in conventional AC switchyard equipment and converter transformers. Plant cost reductions have almost equalled the national rates of inflation. The effective cost reduction has been achieved mainly by improvements in both thyristor ratings and thyristor manufacturing techniques.

Costs for AC switchgear have increased. Switchyard costs will be influenced, however, by power authority requirements and design standards.

The following generalised costs refer to converter stations with valves, transformers (including spare), filters, DC equipment, auxiliaries, controls, and engineering, but exclude buildings, AC switchgear and telecommunications. Except for the monopolar station on the Faeroes, costs encompass the equipment for both ends of the link, i.e. they are 'scheme' and not 'per end' costs.

- $102/kW for 300 to 350 MW poles at 330 kV
- $ 87/kW for 450 to 550 MW poles at 330 kV
- $ 77/kW for 600 to 700 MW poles at 330 kV
- $120/kW for a monopolar 60 MW station (Faeroes) with full voltage and surge current ratings

If static compensation were required, its cost would be approximately $20/kVA.

Equipment, including auxiliaries for a "1½ breaker" bay is expected to cost the following amounts. These represent approximately 10% pa increases over the last 5 years

- $550,000 at 220 kV
- $770,000 at 400 kV

Buildings and civil works for the DC and AC constitute approximately 10% of equipment costs.

2.5.2 Scheme Capital Costs

For the arrangement shown in Figure 2.2, the estimated combined capital costs for both terminal stations are as set out in Table 2.2 below

Table 2.2
Station Capital Costs

Plant	Number Required	Cost $ Million
Converter Station - 3x330 MW bipoles	2	204.0
400 kV AC switchgear bays	12	9.2
220 kV AC switchgear bays	12	6.7
Building and civil		22.0
General & Engineering contingencies (10%)		22.0
TOTAL		263.9

An economic life of 40 years has been assumed.

2.5.3 Annual Costs

Converter station operation and maintenance costs are taken as 1% of capital costs. Although the satellite link to Iceland has not yet been established, the possible annual charge for the rental of two dedicated channels will be $0.2 million.

3. APPRAISAL OF HVDC CABLE AND OVERHEAD LINE TECHNOLOGY

3.1 Review of Principles and Parameters

3.1.1 General

As stated in Part 2 and the original report, the capabilities of conversion equipment are well established and the requirements for this scheme can be reasonably well defined. Continuing research is improving the costs and reliability of conversion plant.

Roughly 80% of the scheme's capital cost will be devoted to the transmission cables and overhead lines and of this more than 90% will be attributable to the undersea cables. Unfortunately, the technical and cost features of the cable system are much more difficult to define that those of the converter stations and sea bed conditions along the route will exert a dominating influence.

The capabilities and parameters of cables and lines were described in the original report. Apart from a review of requirements this report will concentrate on developments since the mid 1970's.

3.1.2 Cable Types

The characteristics and limitations of three undersea cable types were detailed in the original report. The cables were classified according to insulating media.

- oil filled with paper insulation, the oil being of low viscosity
- gas filled with pre-impregnated paper
- 'solid' oil/paper insulation using a high viscosity oil which would undergo negligible local migration during the life of the cable

For long sea crossings, these cable types have differing suitabilities.

Oil Filled Cables:

This type of cable can be used only for very short routes as oil reservoirs are necessary to maintain adequate oil pressure and contain oil movements resulting from thermal expansion and contraction.

In addition, oil filled cables are usually manufactured in short lengths so excessive jointing would be required for this project. Reservoirs could not be provided in mid ocean.

Oil filled cables cannot, therefore, be used for this scheme.

Gas Filled Cables:

Interest in the development of gas filled cables has been diminishing over the years.

If a gas filled cable were to be located in deep water, an extremely high gas pressure would have to be maintained to counteract cable crushing due to the external water pressure. To prevent water ingress at mechanical faults, gas pressure must be higher than maximum water pressure. In addition, allowance must be made for gas movement over very great distances during expansion and contraction of the cable, or before and after repair jointing.

Jointing itself would be a difficult and protracted activity due to the degassing and regassing and the need to prevent water entry. If water entered the cable, substantial lengths would have to be replaced, thereby delaying the return to service.

Even though gas filled cable permits slightly higher electric stressing (kV/mm) than solid cables, the above mechanical complications preclude its use for this scheme.

Solid Oil/Paper Cables:

As elaborated in part 3.2 of this report, solid cable presents now the only feasible solution to the problems of the long and deep sea crossing between Iceland and Scotland. No movement of the insulating medium in the cable is entailed and the cable can be manufactured in long lengths.

3.1.3 Overhead Line Types

For HVDC overhead line transmission, the principal line configurations are monopolar or bipolar. With the former, either a second monopolar line or earth can be used for the return circuit. With the latter an earth return can be used for an outage of one pole.

For a given power transmission requirement, DC lines are roughly 30% cheaper than AC as insulation levels are lower, tower profiles are smaller, conductor permissible current loading is higher and lower corona levels mean fewer and larger diameter conductors can be used instead of multi-conductor bundling.

The selection of the line configuration will be dependent on economics, acceptable levels of supply security, environmental aspects of the lines and way-leave availability.

3.1.4 Electrical Requirements for Cables

Unlike AC cables, where electrical stress grading is mainly a function of permittivity, insulation conductivity is the critical parameter determining cable insulation performance under DC conditions. As well as having to be suitable for working DC stresses, a cable must be able to withstand voltage reversal or step changes and transient over-voltages caused by converter station faults and AC system disturbances.

An intrinsic problem with oil/paper insulation under DC conditions is that the conductivity of the insulation is influenced by temperature and applied electrical stress. As a result, the highest stress gradients occur near the conductor in an unloaded cable and near the sheath if the conductor temperature is raised sufficiently. In general, a maximum temperature of approximately $50^{o}C$ is usually imposed on the conductor so that electrical stress instability and failure adjacent to the sheath do not occur.

A supplementary effect of the limitation imposed on the temperature gradient across the insulation is that sea water temperatures have much less effect on the current ratings of DC cables than AC cables. Burial of this type of DC cable in the sea bed imposes negligible derating.

Gas and low viscosity oil filled cables have an advantage over solid cables in that the insulating medium is sufficiently mobile to take up thermal expansion and contraction of the cable insulation. With solid cables the possibility exists that the relatively inelastic lead alloy sheath may allow insulation voids to form after excessive expansion of the central conductor, insulation and subsequently sheath. The outcome can be electrical failure after the insulation cools and voids are created by negative pressure. Maximum stress gradients in solid cables are usually limited to approximately 30 kV/mm. The highest working voltage in an existing undersea solid oil/paper cable is 263 kV in the Skaggerak link. This corresponds to 250 kV nominal. For the planned Cross-Channel link, 270 kV nominal voltage solid cable is proposed.

Electrical performance will be influenced by conditions at one or more terminii as in deep water the temperature is cooler and compressive forces improve the insulation strength.

An additional requirement, particularly in the waters around Britain, is that of minimised interference to navigation where a magnetic compass might be used. In the case of the proposed 2 GW Cross-Channel link between England and France, forward and return cables in a pair will have to be buried in the same trench to nullify the magnetic field effect.

3.1.5 Mechanical Requirements for Cables

The lead alloy sheath over the insulation prevents the ingress of water. The electrical loading pattern, both in magnitude and frequency of load changes, affects the expansion and contraction of the sheath via the conductor and insulation. The pattern of load cycling of a cable must be examined, therefore, so that the risk of fatigue failure of the sheath is minimised.

In the case of the Iceland-Scotland scheme, it is expected that the current will remain relatively steady in the long term provided the scheme remains a unidirectional supplier of base load energy.

The principal limitations occur with tensile, torsional and impact stressing of the cable. The armouring must be sufficiently strong to permit laying and retrieval and resist impact loads, such as from fishing trawls, and chafing in rocky areas.

Cable joints, whether they be made in production or at sea, must be compatible with the mechanical and electrical strength of the basic cable. The manufacture of satisfactory flexible joints has been a problem with undersea power cable and the reliability of joints has caused concern.

3.1.6 Routing Requirements

The selection of a route for an undersea cable may have to be a compromise between economics, which generally dictates the shortest route, and cable protection which could require a more circuitous route.

The principal influencing factors are as follows:

- sea bed conditions where abrasion or bending may occur, particularly if sea currents are strong. In particular, bottom conditions are most important if cable burial is required.

- fishing areas, where possible trawl damage must be minimised. Cable burial may be required.

- water depth which directly influences the tensile strength of the cable so it can be laid and retrieved. In addition, it governs cable spacing and corridor requirements.

- maximum water temperature at the warmest landing point, in that it will exert some influence on the cable rating.

- route length as it governs the number of sections in which the cable is to be manufactured and transported as well as the cost.

- landing sites which should be sheltered and provide suitable sea bed conditions for protective burial.

3.2 Cable and Overhead Line Developments

In the last five years there have been a number of developments in DC cable and line design, although undersea cable developments have been more marked and they exert a greater impact on scheme viability. Advances, relevant to this project, are described in the following sections.

3.2.1 The Skagerrak Scheme

The most important new project in undersea HVDC transmission in the late 1970's has been the Skagerrak link between Norway and Denmark. The 125 km crossing of the Skagerrak sea involved the laying of heavily armoured cable in waters up to 550 m deep. No scheme prior to this necessitated the laying of cables in such deep waters. New designs and laying techniques, for both the cable and its flexible joints, had to be developed.

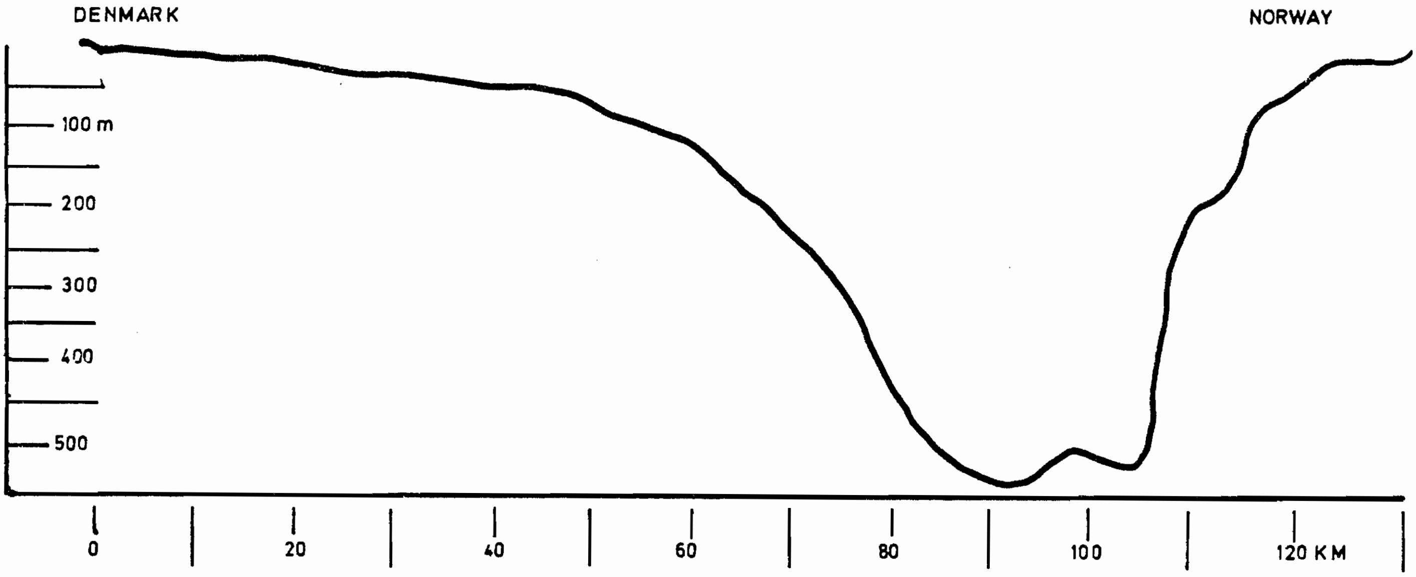
The two sea cables, each having 800 mm^2 copper conductor with a rating of 1000 A at 250 kV, were laid in single lengths. For transport and laying a special vessel, containing a deck-mounted 32 m diameter turntable, was constructed. The weight, in air, of one metre of cable is 48 kg.

Double steel wire armouring, of opposite lay, protected the circular section oil/paper cable from the risks of kinking and twisting during laying. In addition, the armouring provides resistance to insulation damage resulting from impact and bending forces.

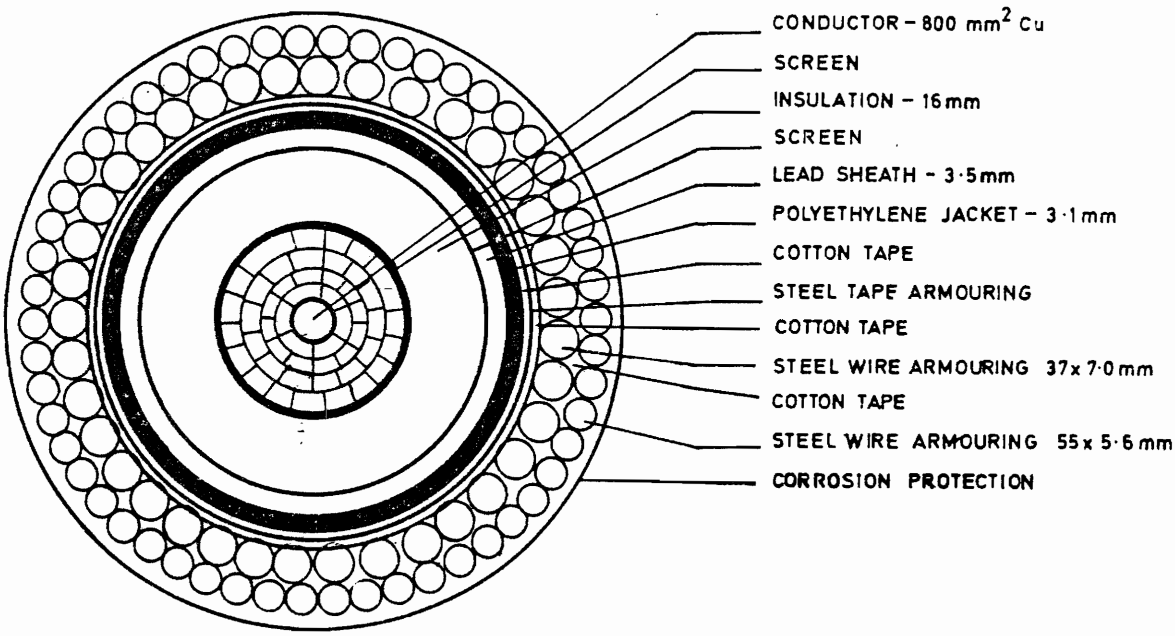
In Figure 3.1 is shown the composition of these cables and the depth profile of the sea bed.

3.2.2 The Proposed English Channel Link

A new HVDC link between England and France is planned for the mid-1980's. Although no contracts for cable supply have yet been let, it is proposed that British and French manufacturers will



DEPTH PROFILE OF ROUTE



CABLE CROSS SECTION

FIG. 3.1 THE SKAGERRAK H.V.D.C. LINK

contribute to the scheme requirement of 8 cables, each 270 kV and 925 A, for a transmission capacity of 2000 MW.

As a compromise between the manufacturing industries, and to minimise the risk of oil discharge after cable damage, each of the 50 km cables will be of the solid oil/paper insulation type.

The single armoured cables, weighing 30 kg/m, will be laid (in pairs) in 1.5 m deep trenches to minimise the risk of trawl and anchor damage.

3.2.3 Insulating Materials for Cables

Although most emphasis has been placed on the development of the mass impregnated solid cable for DC applications, as used for the Skagerrak link and proposed for the Cross-Channel link, some work has been done on polymeric materials such as cross-linked polyethylene (XLPE or PEX) insulation. For AC applications working voltages of 150 kV are now accepted and higher voltages are expected after further development work. XLPE cable is soon to be used on some 220 kV systems.

XLPE has a number of mechanical advantages over impregnated paper insulation, such as increased resistance to crushing or impact forces and better bending and jointing capabilities. As it is impervious to water, lead sheathing can be thinned or even eliminated.

Unfortunately, the attempts to adapt XLPE to HVDC use have not been successful to date. Electrical stress distribution with DC is dependent on the conductivity of the insulation and the high resistivity of XLPE and space charge effects have meant that breakdown levels are very indeterminate. Unless the basic parameters can be altered by chemical modification, XLPE's suitability for HVDC seems very limited.

Although some research into the use of XLPE for HVDC is continuing, there is little inducement to accelerate it as the industry sees too few applications at this stage to justify the expenditure.

3.2.4 Uprating of Solid Cables

Because of difficulties in designing flexible joints which would withstand cable laying and retrieval, the operating voltage for the Skagerrak cables was set at 250 kV. Subsequent development work, including closer quality control and more rigid tolerance requirements for both the semi-automatically made production joints and the repair joints made at sea, has resulted in an improved capability. Type testing for 350 kV, in accordance with the internationally accepted CIGRE testing recommendations, has now been completed satisfactorily for this cable by one manufacturer who expects that further research and development will produce a 400 kV, 500 MW cable within the next 5 to 10 years.

A conservative approach is adopted by the English and French electricity supply industries so a maximum voltage of 270 kV is proposed for the new link. Concern about the risk of insulation void generation after lead sheath expansion compels the UK industry to claim 300 kV as an upper limit to solid cable voltage. For such higher voltages, further research work would have to be funded.

Even though increases in either voltage or current ratings introduce the possibility of reducing the total number of cables required in a scheme, there is an optimal relationship between voltage and current for a particular power rating of solid DC cable. This optimisation is a function of a number of economic and technical factors, including thermal stress grading across the insulation. Although current ratings of approximately 1500 A per cable are achievable, a lower rated 1000 A cable is more suited to working voltages in the range 250 to 350 kV. This applies to the type of cable employed in the Skagerrak crossing.

3.2.5 Armouring of Cables

Not only is cable armouring used for basic protection, but it also provides the necessary tensile and torsional strength during laying and retrieving. For the laying of the Skagerrak cables in the 550 m deep sections, tensile forces were of the order of 23 tonnes. For this and protection against impact, kinking or twisting, double steel wire armouring of opposite lay was found to be necessary.

Unfortunately such rigid cable is difficult to handle so conventional coiling methods could not be used. Instead the cable had to be loaded onto and unloaded from turntables.

As well as providing the required rigidity and strength when laying in waters deeper than 300 m, heavy double armouring gives adequate protection against 1 to 1½ tonne "otter board" fishing trawls. The advent of the heavy beam trawls (several tonnes) has resulted, however, in severe damage to all forms of heavily armoured cable, so armouring is considered inadequate in these circumstances. For such protection, burial appears to be the only solution if the area in question cannot be avoided.

3.2.6 Burial of Cables

Burial provides good protection against trawl damage and moderate protection against anchor drag. It can be regarded as a supplement to armour protection as only endangered sections of cable routes require burial.

After two cases of cable rupture by beam trawls, approximately 30 km of the Skagerrak cable route were buried. This was done not long after the scheme was commissioned and has proved to be effective as no further faults have occurred.

In the case of the proposed English Channel crossing, the risk of anchor drag is large. Consequently cables will be trenched approximately 1½ metres into the soft rock (chalk) bed. Whilst this approach may be understandable in a zone of very high density shipping traffic, the probability of a ship's anchoring near the route of an Iceland-Scotland cable is low. In addition, there will be relatively soft-bottomed areas along the North East Atlantic cable route where the anchor from a very large ship could penetrate to depths of several metres. For these reasons cable burial, solely for protection against anchor drag, is not considered justifiable for this scheme.

To avoid beam trawl or very heavy otter board trawl impact damage it is necessary to bury the cable. Beam trawling is restricted to water up to approximately 100 m depth as this technique is used only to catch flat fish. However, beam trawling is not conducted in the north east Atlantic and there appears negligible prospect for its being introduced. The extent of cable burial required must be determined by a probabilistic approach to damage. This should take into account likely fishing areas and fishing densities. Cable burial is so expensive, approximating the cost of the cable itself for the Cross-Channel link, that an accurate knowledge of route conditions would be required before a scheme could be costed in detail. In general, a burial depth of up to 1 metre should suffice if anchor drag is not to be considered.

An alternative to burial, as a form of protection against trawling, was used in the Italy-Sardinia link. Steel cables were suspended in catenary form above the cable route. While providing a satisfactory protection, it destroys trawls. Such a scheme could not be envisaged for deep and open waters.

Work on the techniques for burial of the Skagerrak and new Cross-Channel cables has produced devices for jetting, ploughing or cutting of trenches. For the Skagerrak cables various techniques were tried, culminating in a sea bed crawler with jetting action. For the channel crossing, it is expected that a trench cutting machine will be used. This machine will lay a steel guide cable in the trench. At a later stage a plough will winch itself along the guide cable and feed the power cable into the trench vacated by the guide.

Although trenching techniques may need to be developed for this scheme, technology from the oil/gas industry could be incorporated in cable burial proposals. The need to bury small diameter steel pipelines and umbilical cables in the North Sea has spurred development of new types of sea bed crawlers which can work in depths up to 200 or 300 metres. Such devices will jet or plough trenches and then bury a prelaid pipe. It is expected that extensive use will be made of TV surveillance in the trenching/burial operation.

While burial to 200 or 300 metres may be considered necessary to minimise the risk of trawl damage, deeper water often provides some protection as sand and mud sedimentation generally increases with depth. Consequently, cables can sink into such sediment, provided there are no strong water currents to remove the covering.

Finally, protection against chafing is achieved mainly by avoiding heavy current and rocky areas of the sea bed. The comparatively rigid double armouring provides an inherent element of protection against such damage to those sections of cable which hang as a catenary between support points in rough terrain. In areas of sand waves, however, unacceptable cable catenaries may be formed.

Summarising, it can be said that a cable from Iceland to Scotland should be double (opposite lay) armoured throughout its length with the emphasis on protection capabilities in shallower waters and tensile and torsional strengths in deeper waters. Where a substantial degree of fishing is expected in waters up to 200 m depth, some burial of the cable to a depth of approximately 1 metre may be advantageous. If burial is too difficult or too expensive the route should avoid the area in question.

3.2.7 Cable Jointing and Laying

Heavy undersea cables are made in lengths from 10 to 50 km, sheathed, jointed and then armoured overall. Flexible joints are required so that the joints as well as the cable can be handled by the capstans and guides on the cable laying vessel. Apart from joints made at sea, where the armour splicing results in an overall cable diameter which is only a few millimetres greater than the basic cable, the cable joints should, as far as possible, be homogeneous with the cable.

As stated in 3.2.4 continuous improvements to quality techniques for jointing during production and at sea have meant that electrical performance restrictions are being eased. Further improvements are expected when larger diameter capstans (e.g. 10 metres) are employed as bending radii will be increased.

Based on the assumption that manufacturing and transport limitations would restrict one section of cable to a weight of, say, 15 000 tonnes (in air), a special ship or barge would be required to carry the cable. The purpose-built vessel used for the laying of the Skagerrak cables can carry approximately 7000 tonnes of cable.

As an alternative to constructing a new vessel, it may be possible to modify a semi-submersible craft of the type used to lay oil/ gas pipelines in the North Sea. These vessels can carry substantial weights of reeled pipeline, are stable in heavy seas and are self propelled with a speed of approximately 10 knots.

A further outcome is that a cable between Iceland and Scotland would have to be made in at least 4 sections and these sections then jointed at sea. Consequently, high standards of materials, workmanship and equipment would be required not only during production jointing, but also at sea. The same techniques would be used in jointing the sections as well as repairing any faults. As power cable is more delicate than telephone cable, the vessel used for jointing would have to be suitable for maintaining a stable position while holding a cable end.

Interest is increasing in the possible jointing of sea cables in-situ. Techniques are already available for undertaking pipeline welding repairs on the sea bed using a habitat lowered from the surface. The pipe is lifted approximately 1 metre and enclosed by the structure. The sea bed habitat, which can offer a controlled environment, is accessible by submersibles. There is no significant water depth limitation. As well as eliminating the need for a standby cable repair ship, the method offers the advantage that long cable inserts are not required when repairing faults.

It can be seen that the coordinated timing and rate of manufacture, laying and jointing of all cables in the Iceland-Scotland scheme would need to be analysed carefully. For example, cable laying is likely to be carried out in the period April to September only as weather conditions are then at their best. For practical purposes a complete cable (950 km) should be laid in one season.

Some manufacturers claim that the way is now clear to design cables and laying machinery where the route traverses areas with a water depth up to 1200 metres. With such a capability, some choice would be available in selecting a route between Iceland and Scotland, and substantial use could be made of the protection offered by very deep water.

3.2.8 Overhead Line Design

While no radical changes in the basic design of monopolar and bipolar lines have occurred lately, there have been some installations using double bipolar circuits on one tower. This arrangement was used on both the Norwegian and Danish ends of the Skagerrak link. Consequently each tower supports circuits with a total capability of 1000 MW.

Developmental work is continuing on the use of composite insulators, i.e. insulators made of fibre glass cores surrounded by mouldings of resin or silicone rubber. Although a few AC lines employ these new rigid insulators, further in-service experience and development work will be requied before their general acceptance by power authorities. When introduced on a substantial scale, it is expected that line costs will be reduced. This will be due partly to reduced insulation costs and partly to the change in tower profile.

3.3 Cable Reliability and Routing

3.3.1 "Scotice" Communication Cable

In January 1962, a telephone/telegraph cable linking Iceland, the Faeroe Islands and Scotland was commissioned. The northern section ("Scotice North") is controlled and maintained by The Great Northern Telegraph Co. Ltd and the southern section, i.e. from Faeroes to Scotland, by the British Post Office. The sea cable is armoured throughout, but the heaviest, or double, armouring is used in the shallowest waters with emphasis on fishing areas. In general, such types of cabled routes are armoured (single or double) for depths to about 700 metres. Trawling does not usually extend beyond 600 metres depth so armouring is considered unecessary. The unarmoured lightweight cable has sufficient tensile strength for laying and retrieval. This cable is of considerable interest to a possible HVDC link as information on its reliability and routing can be used in assessing HVDC cable performance and routing.

It is appreciated that considerable divergence between routes would occur near Iceland, as the communication cable terminates at Vestmannaeyjar while the DC cable route is likely to start in the Sudur Mula Sysla region on the south eastern coast.

References to "Scotice South" cable faults and reliability were made in the original HVDC Study report of April 1975.

In Table 3.1 is set out a summary of the performance of the two sections of cable since they were commissioned.

Table 3.1
"Scotice" Communication Cable Performance

Cable	Sea length (km)	No. of faults	Nature of fault as % of total				Average outage time (days*)	Average outage rate per year per 100 km
			Trawl	Chafe	Corrosion	Anchor		
Scotice South	530	25	76	20	4	-	12+	0.26
Scotice North	745	12	92	-	-	8	7	0.09
TOTAL	1275	37	81	13	3	3		0.16

* includes ship transit time from port and fault locating
\+ since 1976 only

1 nautical mile = 1.86 km
1 fathom = 1.83 metres

The mean time between failures over the 18 year period was approximately 6 months. If a fault took, on average, 10 days to locate and repair (including travelling time from port), the unavailability of the total 1275 km cable was approximately 5%.

In August 1970 a section of single armoured cable in the Scotice South link which suffered repeated trawl damage was replaced with double armoured cable. The subsequent fault rate decreased markedly. Unfortunately the number of trawl breaks on Scotice North (mainly single armoured) increased substantially since the early 1970's, with the result that the mean time between failures for both cable sections has remained at about 6 months. The repair times for Scotice North has been shorter than from Scotice South so the total unavailability of the Iceland to Scotland link has dropped to approximately $3\frac{1}{2}$% i.e. the availability has increased to $96\frac{1}{2}$%.

From an examination of the fault statistics, it appears that cable breaks have been concentrated in 3 zones where fishing is intensive

- approximately 100 km from the coast of Scotland in waters up to 400 metres deep

- between 50 and 100 km from Faeroes (Scotice South) in waters up to 200 metres deep

- between 100 and 150 km from Faeroes (Scotice North) in waters up to 600 metres deep and with an average fault depth in excess of 400 metres.

The sea bed near the Faeroes is rocky and water currents are strong. As a result, some instances of breakage due to chafing have occurred. Where particular problematic locations can be identified, flexible steel housings have been bolted over the cable to reduce cable bending. This technique cannot be transferred, however, from the telegraphic cables to the heavy DC cables. Fortunately, double armouring provides inherently a similar form of protection.

The authorities controlling this cable realise that armouring will not always protect the cable from damage caused by trawls. Consequently, the general policy is to route a cable through the maximum depths possible and keep away from fishing areas and regions of sand waves and severe water currents. These same principles could be applied to an HVDC cable route.

3.3.2 HVDC Cable Outages

The first Skagerrak cable was commissioned in October 1976 and the second in July 1977. There have been 2 mechanical and no electrical faults to date. Both the mechanical faults occurred on the first cable, one in 1976 and one in 1977. The faults were caused by heavy beam trawls and necessitated the burial of part of each cable, as referred to in part 3.2.6. With no further incidence of such damage, the expensive burial of the cable appears to have been vindicated.

Although the service experience is still limited, data relevant to the above faults show an outage rate of 0.14/year/100 km of route length, i.e. for each 100 km of cable the effective time between forced outages was 7 years approximately. This figure is similar to the outage rate for the Scotice communication cable.

On the basis of the average 2 week outage to move the repair vessel to the fault point, locate and repair the fault, the availability of the 2 cable link has been 98.5%.

A number of cable faults on the Konti Scan HVDC link, between Sweden and Denmark, were caused by shipping. Since a length of approximately 30 km of replacement cable was buried in 1974, the number of failures has decreased. In the buried section only one repair, to a faulty joint, has been necessary.

If none of the 950 km future HVDC cables between Iceland and Scotland were to be buried, the above statistics for the Scotice and Skagerrak cables suggest that each cable could expect an outage lasting, say, 2 to 3 weeks every 8 months. Although such a frequency would be unacceptable, strategic locating or burial of the cable should reduce the expected outage rate to a low value.

While these repair times are 'typical', poor weather conditions could mean extended outage periods. Winds of force 6 Beaufort constitute the approximate limit for such repairs at seas. Long term outages due to bad weather will limit the acceptability of the scheme and weather conditions in the North East Atlantic are notoriously bad.

Statistics on HVDC system behaviour for the period up to 1976 show the following values of 'average system availability' for schemes involving undersea cable links (Table 3.2). 'Average system availability' includes forced outages, but no regular maintenance or testing outages, of cables, overhead lines and converter equipment. The figures give a useful indication of cable reliability, however, as overhead lines and converter stations have suffered far fewer faults than cables.

Table 3.2

Average System Availability of Undersea HVDC Schemes (to 1976)

Scheme and Country		Year Commissioned	Availability %
Gotland	Sweden	1954 & 1970	98.3
English Channel	France	1961	76.1*
	England	1961	81.8
Konti Skan	Denmark	1965	97.4
	Sweden	1965	87.4
New Zealand		1965	99.4
Sardinia		1967	72.6
Vancouver Island		1968	99.4

* Partially due to numerous instances of anchor drag

For the Cross Channel link, an availability better than 95% is aimed for.

3.3.3 Scheme Cable Routing

In selecting a cable route between Iceland and Scotland, the following features have been considered. Oceanographic data to aid route selection is available from the Deutches Hydrographisches Institut (Hamburg, Germany), Institute of Oceanographic Sciences (Surrey, UK) and Stoedisutbugvingin (Thorshavn, Faeroes) and national fisheries departments.

- The intensive fishing areas on the Iceland Shelf, Faeroe Shelf and Shetland Shelf have been avoided, as far as possible. The scope of this study does not, however, justify the detailed analysis of existing and forecast fishing areas. This analysis would be required before a cable corridor survey is undertaken.

- Within the limits of protection, cable laying and retrieval, as deep a route as possible has been selected. However, the heavy current areas at the bottom of the Faeroe Bank Channel have been avoided by selecting a route along the channel flank. This route is a compromise between the heavily fished area of the shelf and the sedimentary protection of the deepest parts of the channel. For the unavoidable crossing of the Faeroe-Shetland Channel, a short crossing has been aimed for.

- The rocky sections of the Iceland-Faeroe Rise should be skirted. Even though trawling is limited over this rise because the sea bed is potentially damaging to trawls, a suitable cable route may be difficult to find.

  It is understood that a route to the north east of the Iceland-Faeroe Rise offers much better bottom conditions than a route to the south west of the rise, and fishing is less intensive on the north east side as the water is colder.

- In general, fishing areas with water depths to about 200 m have been avoided. However, in unavoidable areas some cable burial may be required.

- Crossings of telecommunication cables should be avoided or minimised. Route selection would involve negotiations between the various authorities. It is expected, however, that the Scotice cable will be removed after the new satellite link is well established. Apart from the problem of extended outages in times of bad weather, the technical life of the cable repeaters is becoming limited.

- UK Board of Trade regulations are likely to require that forward and return cable pairs, in waters up to about 100 m near Scotland, are laid in the same trench or side-by-side. Further reference is made in Part 3.4.3.

- Cables should be spaced so that identification and retrieval are easy and safe, and shipping or trawling damage to one cable will not affect another. In addition, allowance must be made for cable repair when a section of new cable has to be spliced-in and then laid on the sea floor. The inserted cable length should not lie across or be too near an adjacent cable.

  If 2 cables were to be laid in 1000 metre depth water, the spacing between the cables should be at least 3 km to allow margins of safety for routing and relaying a repaired section. Consequently a 6 cable system in deep water would require a corridor approximately 20 km wide.

- Provided a tee connection to a small HVDC station on the Faeroe Islands is not required in the near future, the cables should avoid the rocky, high sea current area in and around the Faeroes Shelf and the complexity of landing on the islands. Avoiding the Faeroes does make it more difficult, however, to locate cable faults as the accuracy of the measurement of distance to the point of fault is a function of the length of cable section.

If a future converter station is required, one of the cables could be cut and new end sections joined and laid to the islands.

From an analysis of the above features, three possible cable routes, each approximately 950 km long, have been suggested. The routes are shown in Figure 3.2, together with an indication of sea bed conditions.

Route A traverses the difficult terrain to the south east of the Iceland-Faeroe Rise. While the bottom is generally of a gravel nature, there are scattered boulders in the area. This route is considered the most difficult.

Route B follows the easier conditions between the Iceland-Faeroe Rise and the Norwegian Basin to a landing on the Faeroe Islands. Between the Faeroes and Scotland conditions are apparently mixed gravel and sand with some boulders.

Route C also utilises the protection of the sedimentary deposits to the north east of the Iceland-Faeroe Rise, but, like Route A, follows the gravel/rocky flank of the Faeroe Bank Channel. If a landing on the Faeroe Islands is not required, this may offer the easiest route.

For all routes, the rock strewn area of the Iceland shelf must be negotiated, hopefully making as much use as possible of the interspersed coarse sand/gravel areas if cable burial is required.

It should be emphasised that the route selection has been based on generalised oceanographic data. Before any project were to be instituted, a survey of the various route corridors should be undertaken. If two passes at a speed of 5 knots were to be made over each of two routes, the expected survey cost would be

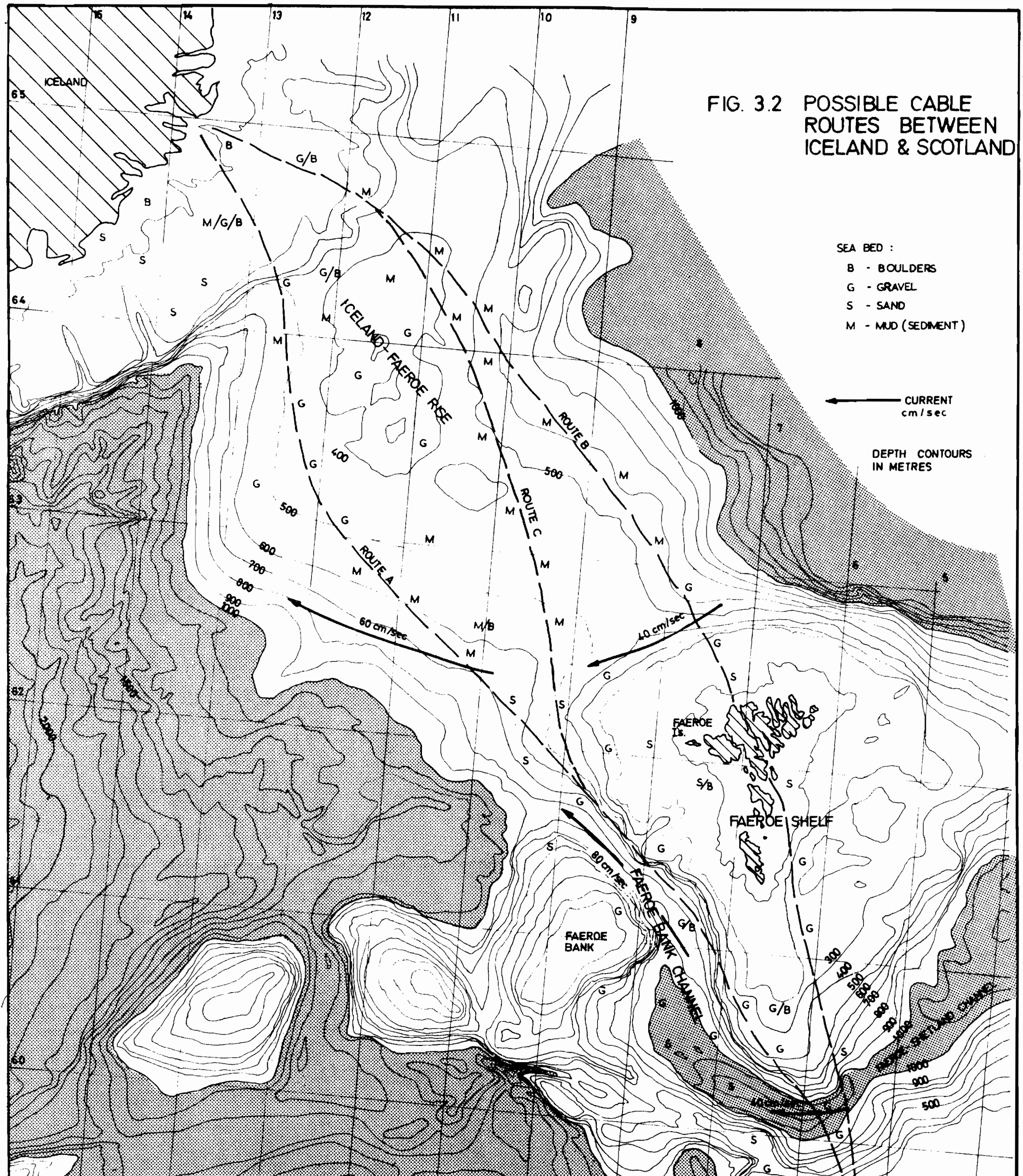


FIG. 3.2 POSSIBLE CABLE ROUTES BETWEEN ICELAND & SCOTLAND
SEA BED :
B - BOULDERS
G - GRAVEL
S - SAND
M - MUD (SEDIMENT)
CURRENT cm/sec
DEPTH CONTOURS IN METRES
ICELAND
ICELAND - FAEROE RISE
ROUTE A
ROUTE B
ROUTE C
60 cm/sec
40 cm/sec
80 cm/sec
FAEROE Is.
FAEROE SHELF
FAEROE BANK
FAEROE BANK CHANNEL
FAEROE SHETLAND CHANNEL
SCOTLAND

approximately $650 000. Conventional navigation, such as Loran C, would be satisfactory for mapping of the route corridor.

For the later selection of individual cable routes, a navigational system with a higher resolution than the approximate 300 m offered by Loran C would be required. The detailed route selection would require sea bed surveying such as high resolution seismic and side-scan sonar.

3.4 Cable and Line Requirements for the Scheme

3.4.1 Cable Ratings

If a scheme were to be instituted soon, the recent technological developments should permit a cable rating of ± 330 kV and 1000 A. These ratings have been tailored slightly to a 2000 MW scheme using 6 cables. As stated previously, the scheme should aim for the minimum number of cables.

Although this analysis will concentrate on a 6 cable arrangement, an 8 cable scheme, similar to the English Channel 2000 MW link, will be examined technically as it represents the limit to which UK and French power authorities are willing to go now while maintaining a high level of reliability and availability.

The extremely high capital cost of manufacturing and laying deep sea cables, together with the satisfactory performance to date of buried sea cables, precludes the introduction of a spare cable.

Using 800 mm^2 copper conductors, the anticipated full load loss per 100 km of route length would be 2.45 MW. Consequently 6 cables, each approximately 950 km long, would give a 140 MW loss. This corresponds to 7.0% of input power. The voltage drop would be 6.7% or 22 kV per pole.

Should expectations of rating increases be realised, a scheme with only 4 cables, each of ± 400 kV and 1250 A may be possible in several years' time. Converter station technology is already adequate for such a scheme. Comments on a possible future scheme are made in part 3.4.4.

3.4.2 Cable Manufacturers

Cable of the required type can be manufacturered now in lengths of only 100 to 200 km per year at any one works. As a result, existing manufacturing facilities would need to be expanded and more than one manufacturer may need to be involved. To avoid jointing dissimilar cables, it is suggested that each manufacturer should make at least one complete cable. If production at a works could be increased to say, 500 km a year, one complete cable could be laid every year if two manufacturers were involved. Each manufacturer would have to stockpile over 2 years. A 6 cable scheme would then be commissioned, in stages, over 6 years. Alternatively, a 250 km per production per annum and stockpiling would require an extended project covering 12 years, which is considered to be too long.

Should a 4 cable scheme be achievable in the future and employ an 8 year project commissioning programme, 250 km of cable per year from each of 2 manufacturers would be required. This arrangement should provide a better compromise between a long project programme and an extensive cable manufacturing commitment.

3.4.3 Navigational Restrictions

In the waters around Britain, care must be exercised that there is negligible interference to the proper functioning of navigational devices. Safety of navigation is administered by the Board of Trade using the Coast Protection Act of 1949.

As direct current cables generate a concentric field which diminishes in inverse proportion to the distance from the conductor, ships' magnetic compasses are influenced by the magnitude and direction of this field as well as the earth's field.

Although each case is examined on its merits by the Department of Trade in conjunction with its technical advisor, the Admiralty, it can be said that any scheme involving HVDC power cables in the continental shelf waters around Britain can expect to include the requirement that the forward and return cables in a DC circuit will need to be adjacent to each other so that cable field effects are nullified. In the case of the proposed Cross-Channel link, cable pairs will be buried in the same trench. The same requirement is expected of the possible link across the Irish Sea to Northern Ireland.

As well as influencing cable ratings, especially in the shallow waters near the landing point, scheme security is reduced by this requirement as physical damage to one cable in a pair is likely to involve the other. In addition, a fault in one cable will mean lifting of the pair for rejointing if operations are to be carried out from the surface.

Pairing of cables introduces a further scheme restriction if unbalanced operation, i.e. one pole with earth return, is permitted only for very short periods; namely, that a cable could not be commissioned without its return cable. As a result, commissioning would have to be delayed until completion of the installation of a complete bipole and corresponding cable pairs.

For this study it has been assumed that pairing of forward and return cables would be required from the Scottish shoreline to a point where the water depth is approximately 100 m, i.e. roughly 50 km route distance. If the cable were to run north-south, a ship heading in the same direction would have its magnetic compass 'trapped' by the cable field only if the ship's course were approximately 1 to 2^{o} off the line of the cable. Ships following a magnetic compass while crossing the line of the cable would undergo a very slight parallel offset in course from the original.

3.4.4 Cable, Line and Converter Configurations

As stated in 2.1.3, converter poles can be rated and assembled to suit a multitude of scheme configurations. Three possible arrangements based on 6 cables are shown in Figure 3.3.

- Arrangement 1 : With 6 x 12 pulse poles, each of 1000 A rating, this scheme is the most expensive because of the size of the converter stations and ratings of items of equipment. However, it offers the highest level of supply security and permits simple cable pairing for magnetic field annulment.

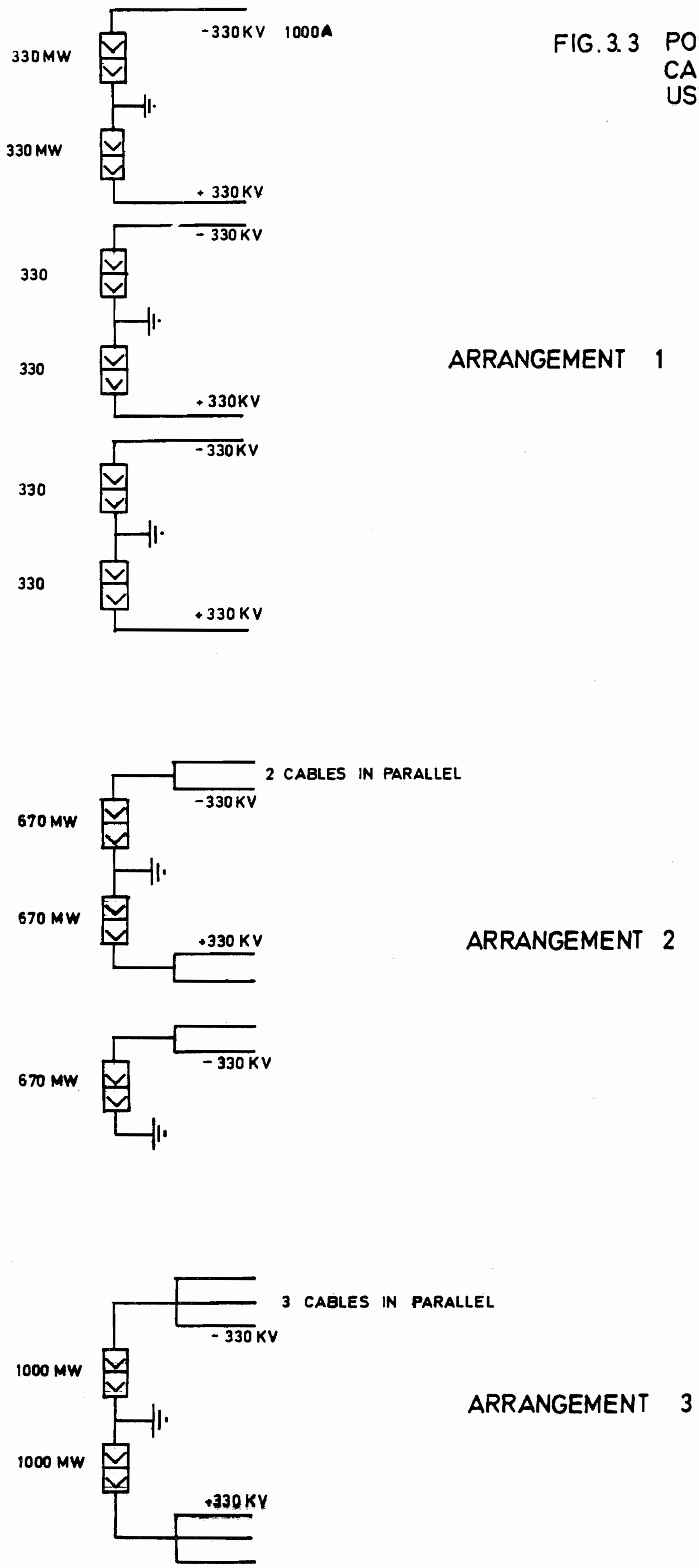


FIG. 3.3 POSSIBLE CONVERTER/-CABLE CONFIGURATIONS USING 6 CABLES

- Arrangement 2 : Failure of a pole would result in the loss of 670 MW until the faulty cable in a parallel pair is isolated. However, this scheme employs one monopole with earth return so does not permit cable forward and return path pairing for field annulment. Although the arrangement offers the best compromise between supply security and converter station costs, it must be rejected unless the Board of Trade requirements are relaxed or the scheme power rating is altered.

- Arrangement 3 : With 3000 A, 330 kV converter poles, the cheapest converter configuration is possible but supply reliability is lowest. System security is further referred to in the following:

In Figure 3.4 is shown the same Arrangement 1, expanded to include the overhead line to the converter station in Scotland and cable pairing in the UK continental shelf waters.

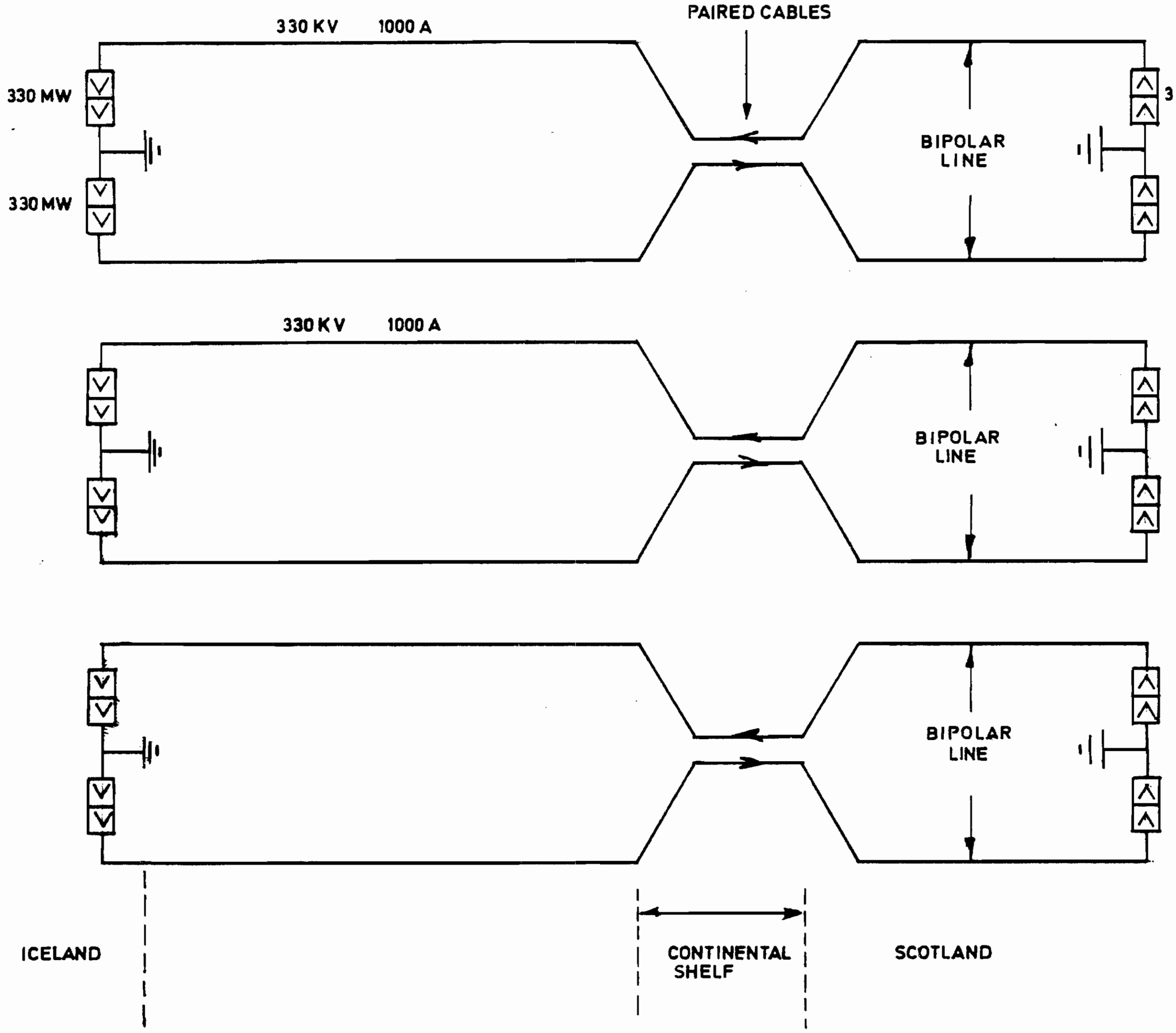
This Arrangement 1 offers the highest level of security, but the highest costs. It will be used as the basis for scheme economic evaluation in Part 5. The main operational features are as follows:

- Failure of a cable pair (continental shelf) or a bipolar line support structure would result in the instantaneous loss of 670 MW. This power level is comparable to the rating of the largest expected generator in the UK system.

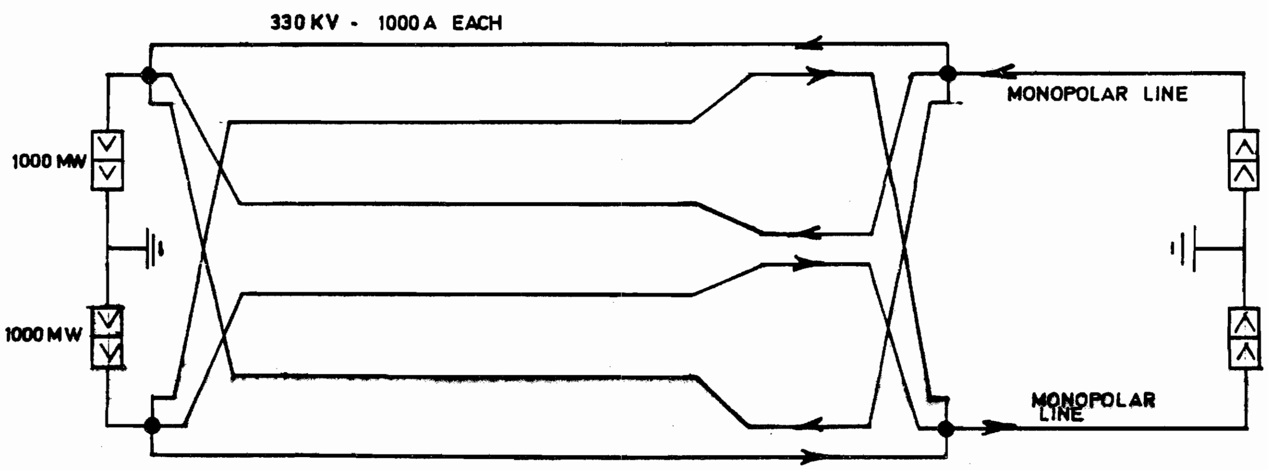
- Providing a temporary 'unbalanced' operation is allowed, failure of a pole in a bipole arrangement would result in the loss of only 330 MW. This assumes, of course, that auxiliaries and ancillaries for the converter stations are designed for the necessary redundancy mode.

Although Arrangement 3 in Figure 3.4 offers the lowest capital costs, a fault on a pair of cables near the Scottish coast (continental shelf) would cause instantaneous loss of the total

FIG. 3.4 CONVERTER / CABLE / LINE ARRANGEMENTS WITH PAIRED CABLES



ARRANGEMENT 1



ARRANGEMENT 3

capability of 2000 MW. Isolation of the faulty cable pair would permit the scheme to operate then in a balanced mode at 2/3 power level, i.e. loss of 670 MW. Failure of one converter pole or one monopole line would reduce scheme capacity by a half, i.e. to 1000 MW.

In Figure 3.5 is shown a cable-intensive scheme based on the proposed Cross-Channel arrangement. Failure of a cable pair would result in an extended loss of 500 MW of transmission capability. Consequently, security is only marginally better than with the 3 bipole arrangement in Figure 3.4, assuming cable faults present the highest outage risk. It should be borne in mind, however, that failure of the cable pair would cause the short term loss of 1000 MW before the faulty circuit is isolated. This loss would have to be covered by spinning reserve on the UK system unless extremely rapid automatic isolation and restoration was possible.

With the requirement of normally balanced bipolar operation, extended outage of a converter or overhead line pole would mean the loss of 1000 MW of capability.

A possible future scheme using 4 higher rated cables and two 1000 MW bipoles is set out in Figure 3.6.

3.4.5 Overhead Line Parameters

The route length of each overhead line from the cable landing point at Cape Wrath to the Glasgow area would be approximately 440 km. The 400 kV network around Glasgow would be more suitable for the absorption of 2000 MW than the 275 kV system to the north which is inadequate for the HVDC scheme power level. Instead of reinforcing the 275 kV AC system and considering incremental losses within it, the cheaper overall scheme with HVDC inverters feeding directly into the lower impedance 400 kV network is preferred.

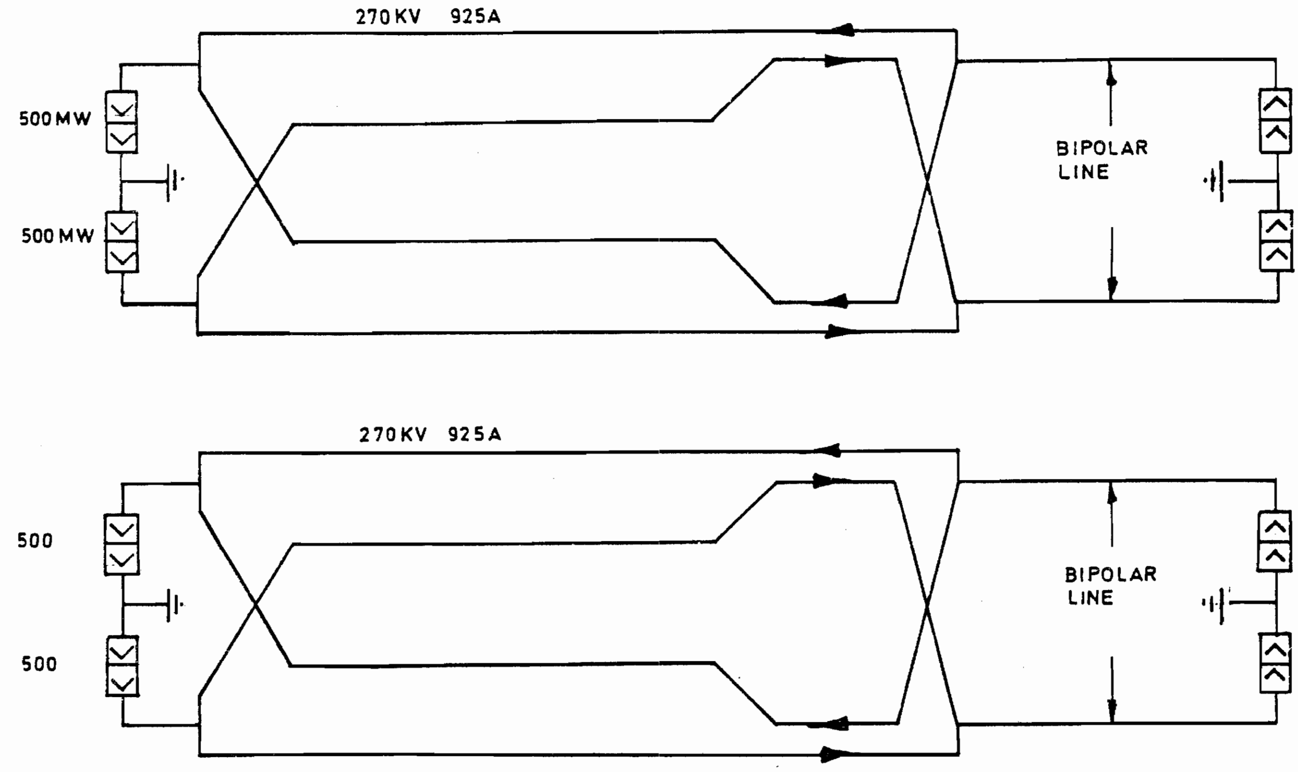


FIG. 3·5 SCHEME USING 8 LOWER RATED CABLES
(as per English Channel)

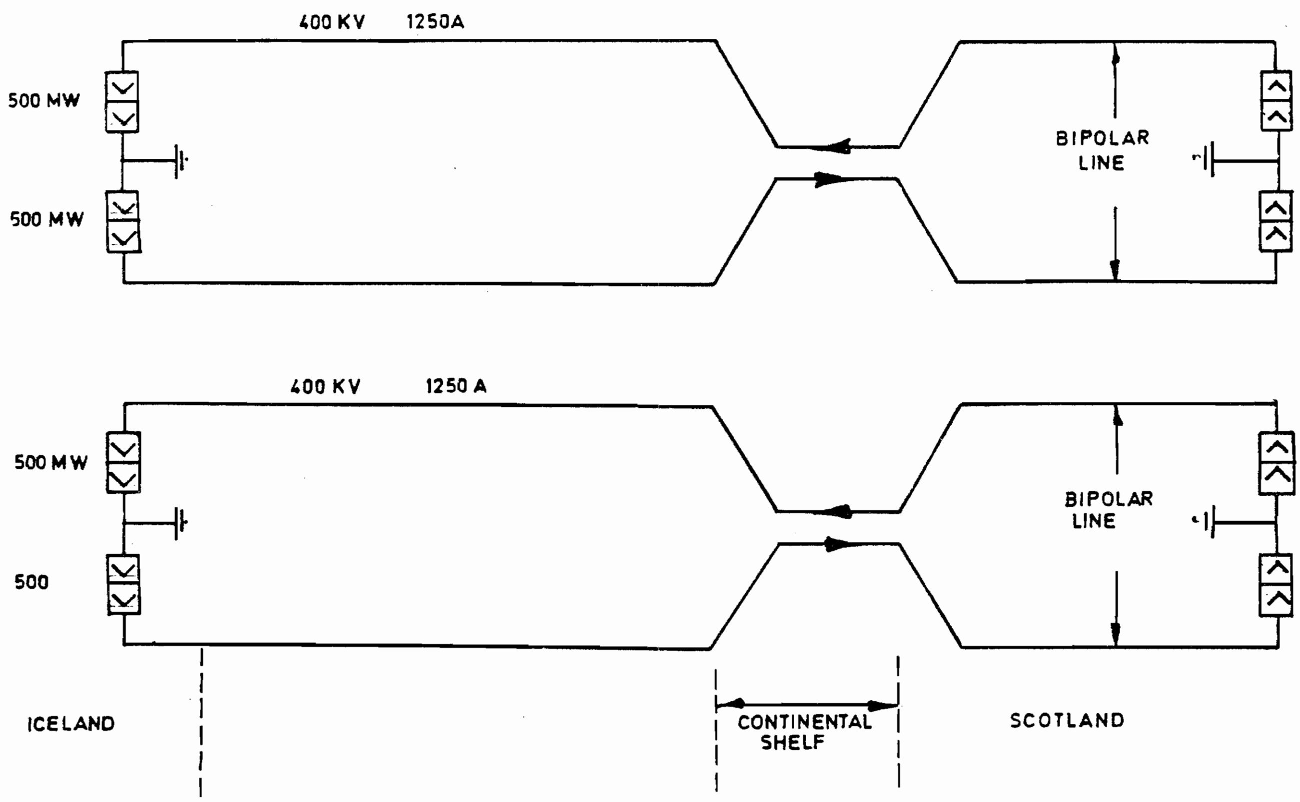


FIG. 3.6 POSSIBLE FUTURE SCHEME USING 4 HIGHER RATED CABLES

Various tower and line configurations are possible for the Cape Wrath to Glasgow overhead lines. Examples are shown on Figure 3.7. The scheme proposed in this report employs three bipolar circuits. While this arrangement is expensive of wayleaves, it offers a high level of security.

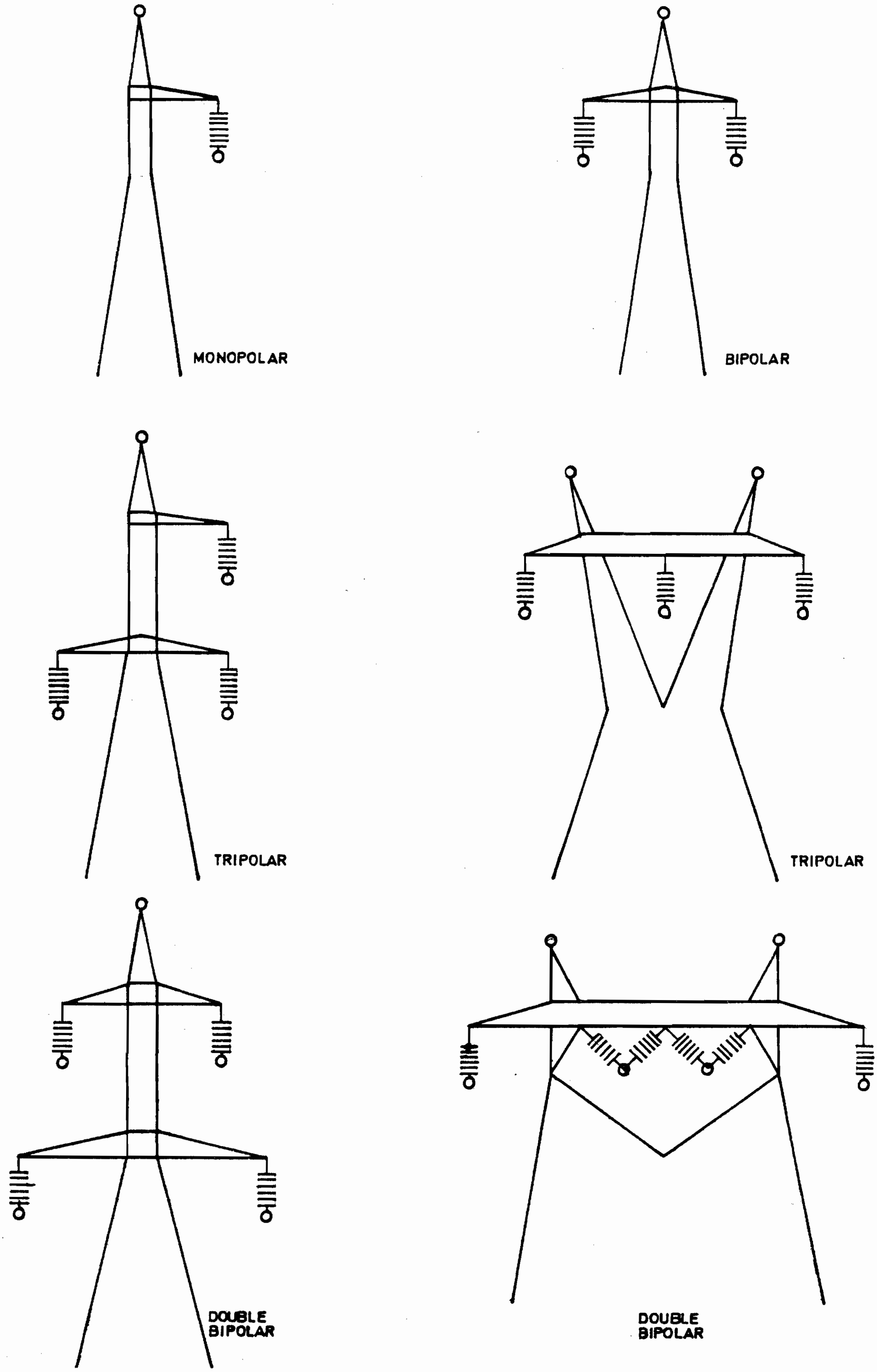
To minimise corona disturbances, the maximum voltage gradient of conductors to air should be approximately 27 kV/cm. In order to achieve this level, conductors with a higher current capacity than necessary must be used. With twin 32 mm (or single 52 mm) diameter smooth bodied aluminium and steel core reinforced conductors, the current rating will be slightly in excess of 2000 A. This assumes a design temperature of 75^{o}C. With a short time allowance of 85^{o}C, the emergency rating would be approximately 3000 A.

Conductor capability could be used more efficiently only if the number of overhead line circuits could be reduced.

Adopting a working temperature of 50^{o}C, the resistance of twin 32 mm conductor would be 0.031 ohm/km.

Hence the voltage drop per pole	=	13.6 kV at 1000 A
and power loss per pole	=	13.6 MW
For all 6 poles, overhead line losses	=	82 MW
	or	4.1% of transmitted power

FIG. 3·7 TYPICAL DC LINE TOWER PROFILES



3.5 Cable and Line Costing

3.5.1 Cable Costs

Cable manufacturing costs are sensitive to movements in international prices of copper, lead and oil and all these have increased substantially over the last five years. A yardstick for the change in cost of manufactured cable is the Retail Price Index (RPI). In Britain, the RPI has doubled in five years.

Budgetary estimates for the cost of supplying and laying double armoured solid oil/paper insulation cable were obtained from both Scandinavian and British manufacturers. For 330 kV, 1000 A cables to satisfy this scheme, the following costs will be applied (Table 3.3)

Table 3.3
Cable Cost Rates

Entity	Unit	Value
Manufacture	$/metre	240
Transport and lay	% manufacture	12.5
Trench & bury down to 100 m depth	$/metre	160
Trench & bury from 100 to 200 m depth	$/metre	250

Allowing for 250 km (150 km shallower and 100 km deeper water) of trenching and burial of each cable, i.e. over part of the west Shetland and Iceland continental shelves and through a small part of the Faeroe Shelf flank, the total capital costs for one 950 km cable in a 6 cable scheme will be approximately $339 million. This figure includes a 30% contingency for the cost of laying the cable and the uncertainty of burial requirements in a sea bed terrain for which only limited data is available.

The approximate cost of a ship to transport the cable sections to site would be $25 million.

With solid cable, maintenance costs would be negligible. This assumes that very few repairs would be necessary over the life of the cable.

3.5.2 Line Costs

Budgetary cost estimates for HVDC transmission lines in Scotland have been obtained from the line construction industry in Britain. Over the past 10 years, the costs of high capacity overhead steel towered transmission lines have escalated at an average rate of approximately 17% pa in the UK. This corresponds roughly with monetary inflation rates.

Using 2 x 32 mm diameter conductors, the costs of monopolar, bi-polar and tripolar lines would be as follows. These costs include surveying, material supply and erection together with a 20% allowance for access difficulties, wayleave clearing and contingencies.

The lines would be likely to traverse areas where ice loading could be a problem. This has been allowed for in design costing.

Monopolar	$ 97,000/km
Bipolar	$ 145,000/km
Tripolar	$ 198,000/km

Consequently 3 bipolar lines, each of 440 km, would cost approximately $ 191 million total.

Line maintenance is taken as 1% pa of capital costs.

4. ELECTRICITY GENERATION IN THE UNITED KINGDOM

4.1 Electrical Network

4.1.1 The Interconnected System

For the purposes of generating and transmitting electricity in England, Scotland and Wales there are three geographic zones, each controlled by a supply board :-

- Central Electricity Generating Board (CEGB) for England and Wales

- South of Scotland Electricity Board (SSEB) for the southern area of Scotland, up to a boundary line which is slightly north of Glasgow and Edinburgh

- North of Scotland Hydro Electricity Board (NSHEB) for the large northern area of Scotland.

While the SSEB and NSHEB pool their resources for operations and planning to meet the electricity requirements in Scotland, the CEGB develops its system independently. The Scottish and English groups do, however, coordinate their requirements to ensure there is no conflict of objectives. As a result of this policy, the 400 kV systems in England and Scotland are linked only by two double circuit 275 kV lines, as shown in Figure 4.1.

In their operating policies, the CEGB and SSEB aim for a net zero interchange. They draw upon each others generating capability in order to optimise production costs or to overcome operating abnormalities. During 1978/79, the maximum (non-simultaneous) exports from SSEB to NSHEB and CEGB were 1.8 GW and 1.0 GW respectively. The corresponding maximum imports from NSHEB and CEGB to SSEB were 0.5 and 1.0 GW.

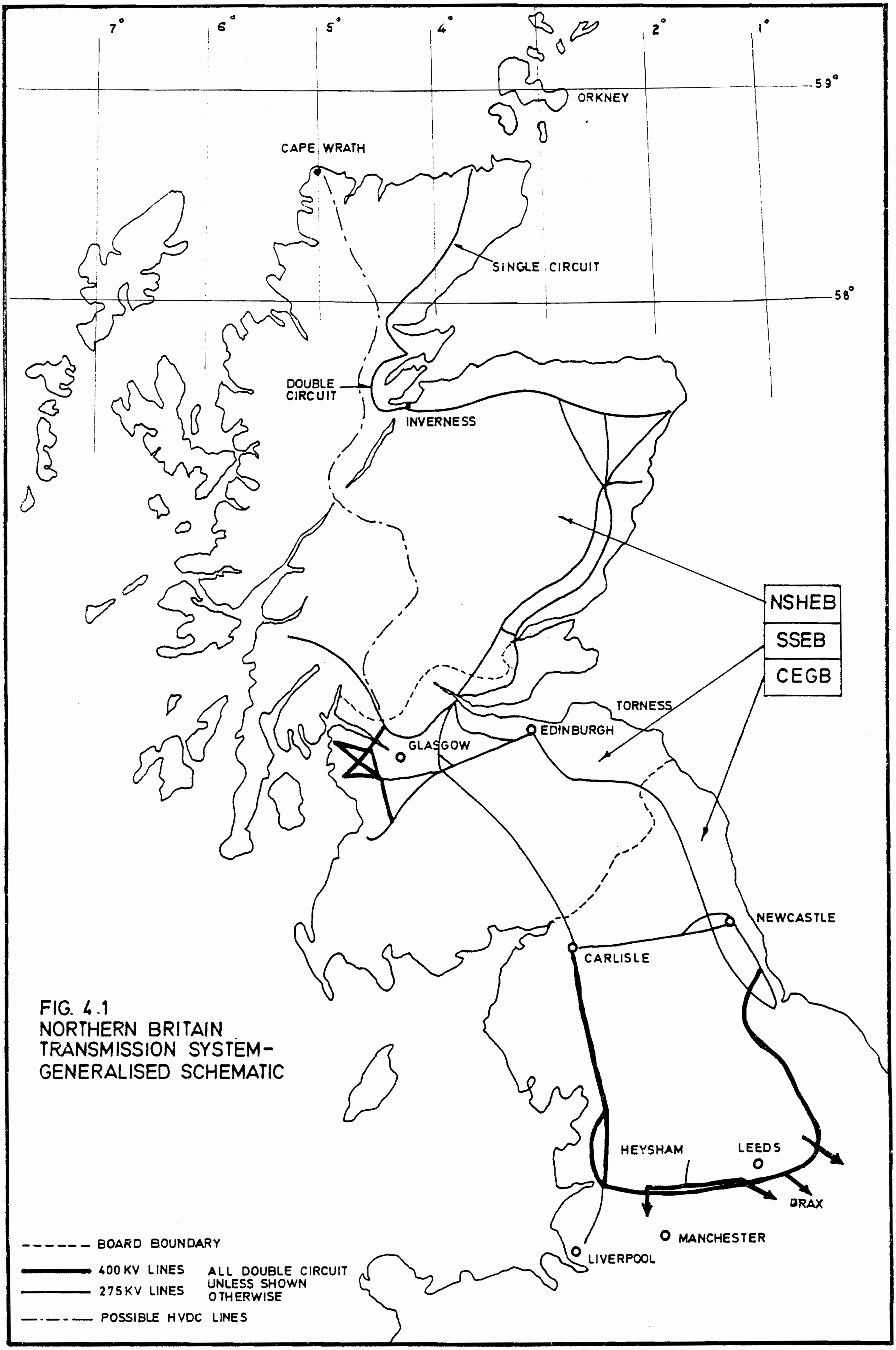


FIG. 4.1
NORTHERN BRITAIN
TRANSMISSION SYSTEM-
GENERALISED SCHEMATIC

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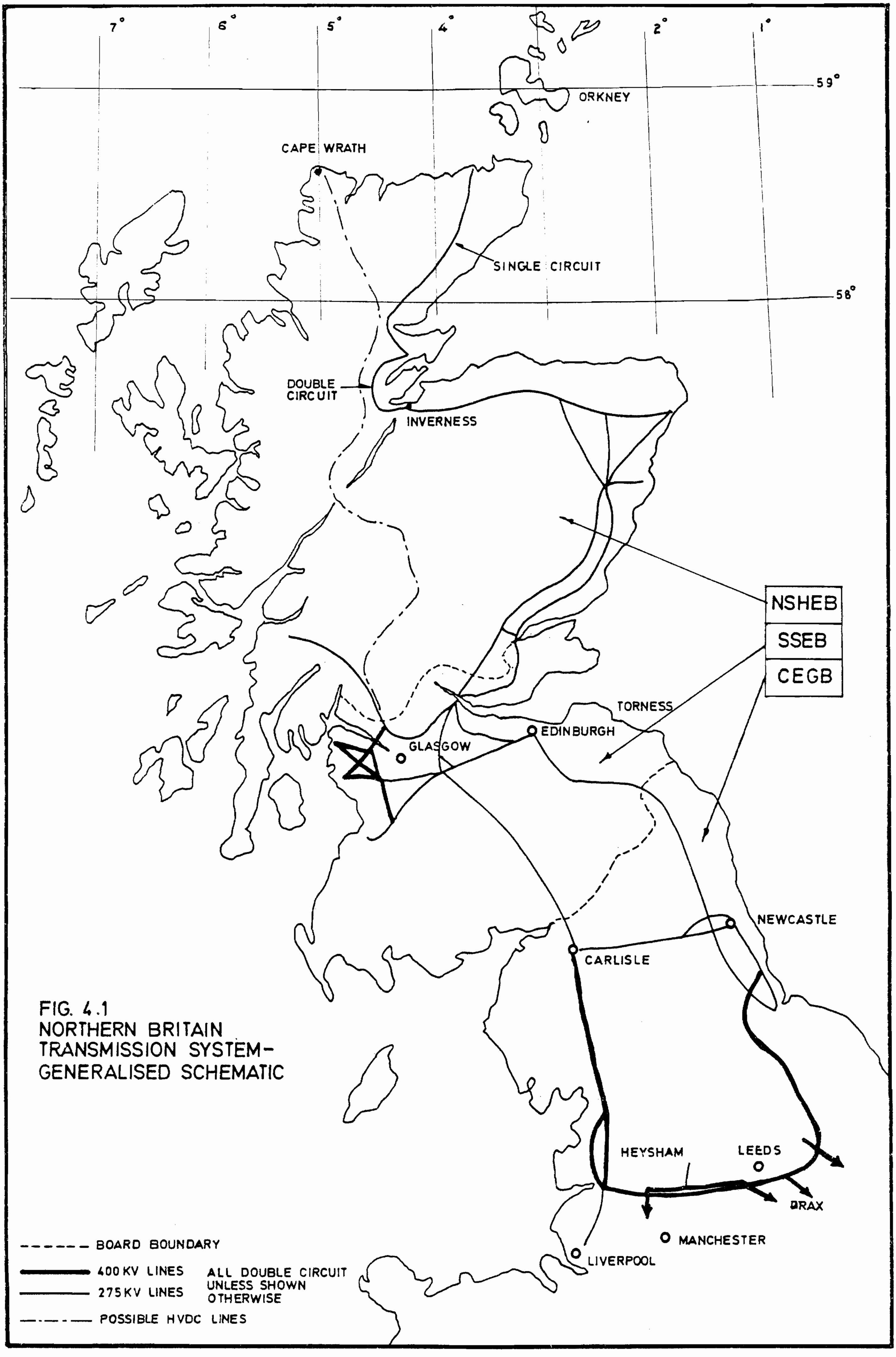

FIG. 4.1
NORTHERN BRITAIN
TRANSMISSION SYSTEM-
GENERALISED SCHEMATIC

As neither the SSEB nor CEGB is obligated to accept a net positive import from the other, the disposal of surplus energy from one system would have to be negotiated between the English and Scottish boards. In fact, an outage of one double circuit line between Scotland and England would mean a transmission capability less than the power rating of the proposed HVDC link from Iceland.

4.1.1 Generation

The approximate distribution of net generating capabilities (power sent out) between the three boards is shown in Table 4.1. 100% represents approximately 65.5 GW in 1978/79.

Table 4.1
UK Plant Capacity

Board	% Installed Capacity by Plant Type					Plant capacity as % of total
	Steam Raising			Hydro & pumped	Diesel & GT	
	Coal	Oil & Gas	Nuclear			
CEGB	61.4*	13.7	6.4	0.8	3.3	85.6
SSEB	6.3	2.6	2.0	0.1	0.3	11.3
NSHEB	-	0.3	-	2.6+	0.2	3.1
Total	67.7	16.6	8.4	3.5	3.8	100

* Includes dual coal/oil or coal/gas fired boilers

\+ Includes 1.1% pumped storage

Generating plant development programmes are substantially dependent on available fuels with national government involvement in policy formulation. Trends in plant development are referred to in the following sections.

On current planning, the largest generating units will be approximately 660 MW. This applies to all types of steam turbine prime movers, whether the steam be raised by fossil or nuclear fuelling.

4.2 The Load Forecast

As a result of both national and international influences, the rate of development of industry and commerce in the U.K. has decreased in the last few years; in particular since the oil crises of 1973/74. In addition, the continued low comparative cost of gas has diminished the competitiveness of electricity. Consequently, the realised demand for electricity has been less than that forecasted previously. The maximum demand recorded on the CEGB system, which is by far the dominant network in the UK, during the winter of 1978/79 was 44.1 GW with a corresponding energy consumption of approximately 225 TWh (to 31st March 1979). During the same period the individual simultaneous maximum demands on the SSEB and NSHEB systems were 4.5 and 1.7 GW respectively. For the U.K. interconnected system, the maximum simultaneous demand was approximately 50 GW. In the 1979/80 winter, the CEGB demand rose to only 44.2 GW.

In the medium term, i.e. to the mid 1980's, it is anticipated that maximum demand and energy will both grow at a rate of less than 1% p.a. and an annual load factor of approximately 56% will be sustained. Prior to the winter of 1979/80, the anticipated growth rate of power demand was 2.2% pa. This means that a CEGB/SSEB/NSHEB unrestricted simultaneous maximum demand of approximately 54 GW can be expected in the winter of 1985/86.

Although the expected growth rate is low, the retirement each year of obsolete generating plant will mean an annual requirement for new plant of at least 1 GW in the mid 1980's.

A new element of uncertainty in growth predictions has been introduced by the consumer pricing of alternative sources of energy, particularly that of natural gas. At the moment most natural gas pricing is dependent on costs of production and hence is a function of the UK home market strength. On the other hand, oil and coal prices are governed largely by international factors.

The net result is that natural gas is now a cheap alternative to electricity. Should gas prices be adjusted upwards in line with governmental policy, it is expected that demand for electricity will increase.

In establishing its load forecast, the electricity industry has assumed that there will be a low to moderate long term growth in the economy and hence electricity demand. While energy conservation and renewable sources of energy are to be considered, it is not likely that they will have any significant impact on the necessary programme for large scale traditional base load generating plant in this century.

4.3 Fossil Fuel Usage

Coal, oil and natural gas are the fossil fuels used by the three U.K. generating boards. Coal is the predominant fuel and is responsible for approximately 70% of annual electrical energy output from all sources.

For some time the generating boards have been concerned about the dependence on coal, especially where government policy has promoted increased coal consumption for the benefit of the coal industry. As the principal aim of the boards is to provide a reliable, uniform supply at the most economic price, they have expressed the need to increase fuel options. In attempting to decrease their dependence on coal, the generating boards have outlined the following difficulties with the present arrangement and scope for change:

- fossil fuel resources are limited and their real prices are expected to rise substantially.

- although oil prices are determined on an international basis, it is expected that in the future, coal and gas prices will keep pace with oil. Increasing scarcity of oil and natural gas will be the principal determinant in energy price rises. The CEGB foresees the doubling of the real price of fossil fuels by the year 2000.

- even though it may be possible to improve both thermal and cost efficiences, it is certain that fossil fuel cost increases will outstrip plant operating savings.

- U.K. mined coal has a viable future on the international market where it is required for uses other than power generation, e.g. in steel making and oil substitutes.

- the electricity industry needs to be relieved of the social costs of keeping the higher cost U.K. coal mines in production, especially when suitable coal can be imported more cheaply.

As the real cost of coal is expected to increase at a rate of approximately 11% p.a. until the mid 1980's while the GDP increases at only 2.5% p.a., the aim of the electricity industry is to increase the precentage contribution from nuclear sources while allowing that from coal to diminish. Governmental policy is to have 30% of electricity generation provided by nuclear plant by the end of this century. Further comments on the nuclear programme are made in the following Section 4.4.

It should be mentioned, however, that fossil fuelled stations will continue as an important source of base and intermediate load energy. Improvements are expected in station quality and efficiency, by way of the control of noxious gas emissions and the introduction of fluidised bed combustion.

Electricity production costs, based on the latest fossil fuel and nuclear generating plants and current fuel costs, are detailed in Section 4.5.

4.4 Nuclear Generation

At least for the rest of this century, the need for an augmented nuclear programme is foreseen by the electricity boards. The programme is regarded not as a substitute for fossil fuel fired generation but as a necessary option. Bearing in mind the comments in 4.3 above, the principal arguments used to support a nuclear programme are the limited supplies of coal, oil and gas and the cheapness of nuclear based generation.

To safeguard future supplies of uranium, the two largest electricity boards (CEGB and SSEB) are participating actively in overseas mining ventures. Through commercial and managerial involvement, the supply of uranium is considered thereby to be more secure. The sources are being diversified so that the political requirements of individual producer nations are less likely to inhibit supply.

Recent governmental decisions in the U.K. have endorsed the aims of the generating boards to expand their nuclear programmes. The intention for the short term is to embark on the installation of more generating stations with 'standardised' British Advanced Gas Cooled Reactors (AGR). New stations, with 660 MW generators, are soon to be constructed at Heysham (CEGB) and Torness (SSEB). Commissioning is planned to start about 1987.

Governmental approval has been obtained also for the introduction of Pressurised Water Reactors (PWR) based on the Westinghouse USA design. Analysis by various U.K. authorities of the accident at the Three Mile Island nuclear station in the USA has confirmed that U.K. safety techniques are basically satisfactory and there is no justification to prevent a PWR programme going ahead in the U.K. As PWR construction is factory intensive, the opportunities for enhanced quality control during manufacture and reduced on-site construction costs are offered.

It now appears that the alternatives for the future nuclear programme will be kept to the AGR and PWR. Proposals for the development of the Steam Generating Heavy Water Reactor (SGHWR) programme have been put aside. This reactor type was considered as an important contender for future nuclear stations when the original study of the HVDC scheme was done in early 1975.

The PWR installation programme is expected to start in 1982, having allowed 2 years for required design modification and approval. Provided no substantial delays in licensing, design or construction occur, the first unit could be in service about 1988/89. Should the first PWR prove satisfactory, the programme is likely to be extended. Such development would be probably to the exclusion of more AGR stations.

It is not expected that the fast ('breeder') reactor will become a commercially viable and socially acceptable energy source for electricity generation in the U.K. until at least the start of the 21st century.

Nuclear development is a matter for political decision and neither major political party is opposed to the principle of a nuclear based electricity generation programme. The only difference is likely to be in extent, with the possibility of a political party providing encouragement or subsidy for the indigenous coal industry and so influencing the ratio of nuclear to coal-based generation.

Even though the CEGB and SSEB are optimistic about the future for nuclear generation, their aspirations are tempered by the possible reaction of some environmentalists to such plans. Wherever possible, open consultation will be held to resolve conflicting interests. An example is the planned public enquiry on the introduction of the PWR. While the nuclear programme is expected to expand, costing will be influenced by the satisfying of new environmental protection and safety requirements.

With an increasing emphasis on the diversification of electricity generation sources, an HVDC scheme could provide a suitable addition to the UK power system.

Towards the end of this century, an HVDC source of 2 GW would constitute an approximate input of 2% only of total needs. Possible concern about the reliability of such an imported supply should be reduced, therefore, by the ability of UK reserve generation to cover it.

4.5 Power Station Costing

4.5.1 General

Two volatile factors affecting the total costing of fossil fuel and nuclear powered generation have been fossil fuel costs, in the case of conventional thermal stations, and capital costs of nuclear stations.

Coal prices have been escalating considerably. The current average price of approximately $ 75/tonne delivered is approximately 3 times the price 5 years ago and more than 5 times the price 10 years ago.

UK Nuclear stations have experienced a number of development problems and troubles with conventional equipment such as steam turbines, generators and pumps. These have increased considerably the capital cost of stations and extended the construction time. Wherever possible, international costs have been examined in this report in an attempt to obtain a more realistic pricing of future stations.

4.5.2 Coal Fired Stations

On the basis of a standardised 660 MW turbo alternator, Table 4.2 sets out the characteristics of typical new coal fired generation in the UK. The units would be similar to those at the CEGB's Drax station where Units 4,5 and 6 are planned for commissioning in 1984, 85 and 86.

In Table 4.3 is set out the phased capital expenditure for a coal fired steam station. To obtain total capital costs relative to the year of commissioning, interest on capital spent during construction has been compounded from the end of the year of expenditure. Interest rates of 8, 10 and 12% pa have been considered.

Table 4.2

Coal-Fired Station Data

Entity	Unit	Value
Generator rated output	MW	660
Auxiliary power requirements	%	4
Unit power sent out	MW	634
Thermal efficiency	%	34
Load Factor	%	75
Construction period	Years	5
Economic life	Years	30

Table 4.3

Coal-Fired Station Capital Costs

Year relative to commissioning	Percentage Expenditure on plant construction and engineering	Cost $/kW	Cost plus interest during construction - $/kW		
			8%	10%	12%
- 4	5	32	44	46	50
- 3	20	126	159	167	176
- 2	35	219	256	265	274
- 1	30	188	203	207	211
0	10	63	63	63	63
Total (Year 0)	100	628	725	748	774

With interest charges at 10% pa, the annuitised total energy costs will be as follows:

Annual charge on capital of \$ 748/kW (annuitised depreciation and interest over 30 years)	\$ 79.3/kW
Operation and Maintenance (2.5% of capital)	\$ 18.7/kW
Total	\$ 98 /kW
For 75% LF, the equivalent energy cost is	14.9 mills/kWh
Coal cost, including transport, is	26.4 mills/kWh
Total	41.3 mills/kWh

4.5.3 Nuclear PWR Stations

With no PWR stations yet under construction in the U.K. and the expectation that design changes will have a substantial effect on costing, it has been necessary to use planning data used by both the U.K. electricity industry and international suppliers.

Anticipated characteristics of a PWR station are set out in Table 4.4. These values assume that a standardised design will permit ultimately a construction time, from site investigation, of 6 years per unit. In addition, extensive operational experience should allow a load factor (LF) of, say, 75% to be achieved. International performance statistics for the period 1975 to 78 indicate that some PWR reactors have been operating with load factors up to 80% while the average value over the period was 66%.

It is probable that 2 x 660 MW steam turbine generator units would be used instead of one 1200 unit. A further alternative is that a lower rated reactor may be used. Decisions on these parameters have not yet been made.

Table 4.4
PWR Station Data

Entity	Unit	Value
Typical reactor size (approx)	MWe	1200
Thermal efficiency	%	33
Generator rating	MW	2 x 660
Auxiliary power requirements	%	4.2
Unit power sent out	MW	630
Load Factor	%	75
Construction period	years	6
Economic life	years	30

Table 4.5
PWR Station Capital Costs

Year relative to commiss-ioning	Percentage Expen-diture on plant construction and engineering	Cost $/kW	Cost plus interest during construction - $/kW		
			8%	10%	12%
- 5	5	61	90	98	107
- 4	20	245	333	358	385
- 3	30	368	464	489	515
- 2	30	368	431	445	460
- 1	10	123	133	135	138
0	5	61	61	61	61
Total (Year 0)	100	1226	1512	1586	1666

If plant is to be commissioned in year 0, the expenditure on plant construction in preceding years is likely to be as in Table 4.5. Interest on year-end capital expenditure during construction has been determined for annual compounding rates of 8, 10 and 12%.

For the case with 10% pa interest charges, the total energy costs, annuitised over the 30 year life, will be as follows:

Annual charge on capital of \$ 1586/kW (annuitised depreciation & interest)		\$ 167/kW
Operation and Maintenance (1.5%)		\$ 24/kW
	Total	\$ 191/kW
For 75% LF, the equivalent energy cost is		29.1 mills/kWh
Fuel cost, including initial charge, reprocessing & handling		8.6 mills/kWh
	Total	37.7 mills/kWh

4.5.4 Nuclear AGR Stations

AGR stations, with approximately 1250 MW output, are expected to have two units with the characteristics set out in Table 4.6. Future stations would be based on the types to be built soon at Heysham and Torness, with a construction time of approximately 6 years per unit. A future load factor of 75% is anticipated, indicative of increased experience with similar types of plant. In the period 1975 to 1978, AGR stations in the UK achieved an average load factor of 64%, but most of the outages were due to conventional (non-nuclear) plant faults.

As in the case of the PWR reactor station, plant capital costs have been determined for each of the 6 years in the construction period and capitalised interest added to give a total capital cost. The results are set out in Table 4.7.

Table 4.6

AGR Station Data

Entity	Unit	Value
Reactor size (approx)	MWe	660
Generator rating	MW	660
Thermal efficiency	%	40
Auxiliary power requirements	%	6.7
Unit power sent out	MW	616
Load Factor	%	75
Construction period	years	6
Economic Life	years	30

Table 4.7

AGR Station Capital Costs

Year relative to commiss-ioning	Percentage Expen-diture on plant construction and engineering	Cost $/kW	Cost plus interest during construction - $/kW		
			8%	10%	12%
- 5	5	64	94	101	112
- 4	20	255	347	373	400
- 3	30	382	481	508	535
- 2	30	383	447	462	478
- 1	10	127	137	140	142
0	5	64	64	64	64
Total (year 0)	100	1274	1570	1648	1731

For a total capital cost of $ 1648/kW, the annual costs will be as follows:

Annual charge on capital		$ 175/kW
Operations & Maintenance (1.5%)		$ 25/kW
	Total	$ 200/kW

For 75% LF, equivalent energy cost		30.5 mills/kWh
Fuel cost, including initial charge, reprocessing & handling		9.2 mills/kWh
	Total	39.7 mills/kWh

4.5.5 Base Load Costs

The costs of base load generation, detailed in the previous sections, can be summarised as follows in Table 4.8.

Table 4.8
Generation Total Specific Costs

Station Type	Generation Cost mills/kWh	Percentage of PWR Cost
Coal-fired	41.3	110
Nuclear PWR	37.7	100
Nuclear AGR	39.7	105

The cheapest of these, nuclear PWR, will be used in the economic analysis of the HVDC scheme in Part 5 of this report.

As inflation will not be allowed for in the economic appraisal, the same generation costs will apply at all stages of the scheme. In addition, it is assumed that a sufficient number of PWR stations will exist so that whatever amount of energy is delivered by the HVDC scheme in a year, the displaced nuclear station energy would have an equivalent cost of 37.7 mills/kWh. For a sensitivity analysis with interest rates of 8% and 12%, corresponding costs would be 32.8 mills/kWh and 43.7 mills/kWh.

5. ECONOMIC ANALYSIS

5.1 Methodology

Under the terms of reference for this study, the annual energy production of the 2000 MW Icelandic generation source will be 16 TWh. This represents a load factor of 91.3%, so it constitutes a base load supply. Consequently, equivalent base load generation in Britain would be displaced by the HVDC system.

For the sake of simplicity it has been assumed that a nuclear or thermal power station has a load factor of 75% throughout its life, even though no nuclear station in Britain has yet achieved this value. In addition, the assumption has been made that full rated output of a generating unit can be achieved very soon after commissioning, although only a few conventional, and no nuclear, stations have yet been able to achieve this.

The CEGB appears to artificially discount the value of energy purchased from extraneous sources, due to limited confidence in the security of this supply. However, no such factor has been applied in this analysis.

A notional HVDC construction programme has been deduced for the economic analysis. Only in the detailed planning stage can this programme be defined accurately.

Using budgeting cost data for base load generation of approximately 2000 MW capability in the UK, the equivalent maximum acceptable generation costs in Iceland will be determined after taking into account the total costs of the HVDC scheme. Energy displacement will be at a common point in the UK grid, in this case the 400 kV network in the Glasgow area.

For the determination of net present values (NPV) of fixed and variable costs, discounted to a common year, the following terms will be used:

X = annuitised cost of the energy source at the input to the AC busbars of the HVDC converter station in Iceland (US mills/kWh)

E = net present value of total energy supplied to the converter station in Iceland over the life of the scheme (TWh)

H = net present value of the capital and operation plus maintenance costs of the HVDC scheme ($ million)

D = net present value of the cost of UK generated energy which is displaced by the incoming energy delivered by the inverter station in Scotland, over the life of the HVDC scheme ($ million)

For the NPV costs of energy delivered to the EHV system in Scotland by indigenous generation and the HVDC scheme to be equal:

$$X.E + H = D$$

$$\text{therefore} \quad X = \frac{D-H}{E}$$

5.2 Determination of Generation Costs in Iceland

Budgeting costs for the components of the scheme have been detailed in this report as follows:

Part 2.5 - Converter Station Costing
Part 3.5 - Cable and Line Costing
Part 4.5 - UK Power Station Costing

In Tables 5.1, 5.2 and 5.3 are set out the HVDC scheme construction programmes and associated cash flows, together with the determination of the NPV of displaced energy from UK generation. A value of 37.7 mills/kWh has been used for the cost of base load generation in the UK.

The phasing of expenditure, as set out in Table 5.1, has been translated to annual cash flows in Table 5.2 using the capital and operating costs previously established in the report. Annual energy inputs, losses and outputs have been listed in Table 5.3 in order to arrive at a total NPV of energy displaced from UK generation (term D).

For the HVDC scheme to be economically viable, the cost of energy delivered to the rectifier station in Iceland should, therefore, be less than

$$X = \frac{4293-2439}{130.8}$$

$$= 14.2 \text{ mills/kWh}$$

Table 5.1

HVDC Scheme Construction Programme

Item	Scheme Year								
	-4	-3	-2	-1	0	1	2	3	4
Shipping	route survey		build ship						
Cable 1	factory A expansion	make 50%	make 50%	lay cable					
Cable 2		factory B expansion	make 50%	make 50%	lay cable				
OH Line 1				erect					
Bipole 1	Network study	construct 20%	construct 30%	construct 40%	10% & co-mmision				
Cable 3				make 50%	make 50%	lay cable			
Cable 4					make 50%	make 50%	lay cable		
OH Line 2						erect			
Bipole 2				construct 20%	construct 30%	construct 40%	10% & co-mmission		
Cable 5						make 50%	make 50%	lay cable	
Cable 6							make 50%	make 50%	lay cable
OH Line 3								erect	
Bipole 3						construct 20%	construct 30%	construct 40%	10% & co-mmission

Table 5.2

HVDC Scheme - Incidence of Expenditure (Capital plus O and M)

Item	Expenditure ($ Million) in scheme year														Total $ Million
	-4	-3	-2	-1	0	1	2	3	4	5 to 40	41	42	43	44	
Shipping	2		25												27
Cable 1	3	114	114	101											332
Cable 2		3	114	114	101										332
Line 1				63.8											64
Bipole 1	0.8	17.6	26.4	35.2	8.8										89
Cable 3				114	114	101									329
Cable 4					114	114	101								329
Line 2						63.8									64
Bipole 2				17.6	26.4	35.2	8.8								88
Cable 5						114	114	101							329
Cable 6							114	114	101						329
Line 3								63.8							64
Bipole 3						17.6	26.4	35.2	8.8						88
Station Maint.						0.9	0.9	1.7	1.7	2.6 x 36	1.7	1.7	0.9	0.9	104
Commun. Link						0.2	0.2	0.2	0.2	0.2 x 36	0.2	0.2	0.2	0.2	9
Line Maint.						0.6	0.6	1.2	1.2	1.8 x 36	1.2	1.2	0.6	0.6	72
Total	6	135	283	446	364	447	366	317	113	4.6 x 36	3.1	3.1	1.7	1.7	2649
NPV of * Total to Year 0	9	180	342	490	364	407	302	238	77	30	0.1	0.1	0	0	2439

* 10% pa rate

Table 5.3

HVDC Scheme - Energy Values

Item	Ref	Unit	Scheme Year									Total
			1	2	3	4	5 to 40	41	42	43	44	
Energy supplied to converter station in Iceland	a	TWh	5.3	5.3	10.7	10.7	16 x 36	10.7	10.7	5.3	5.3	640.0
NPV (year 0) at 10% pa	b	TWh	4.8	4.4	8.0	7.3	Σ = 105.7	0.2	0.2	0.1	0.1	130.8
Converter station losses (2%)	c	TWh	0.1	0.1	0.2	0.2	Σ = 11.5	0.2	0.2	0.1	0.1	12.7
Cables losses (7.0%)	d	TWh	0.4	0.4	0.7	0.7	Σ = 40.3	0.7	0.7	0.4	0.4	44.7
Line losses (4.1%)	e	TWh	0.2	0.2	0.4	0.4	Σ = 23.6	0.4	0.4	0.2	0.2	26.0
Energy received from converter station in Scotland [a - (c+d+e)]	f	TWh	4.6	4.6	9.4	9.4	Σ = 500.6	9.4	9.4	4.6	4.6	556.6
Cost of displaced nuclear energy (at 37.7 mills/kWh)	g	$ M	173	173	354	354	Σ = 18873	354	354	173	173	20981
Present value of displaced energy (NPV of g)	h	$ M	158	143	266	242	Σ = 3465	7	6	3	3	4293

5.3 Sensitivity Study

Three influential variables, namely cable and line cost, UK indigenous generation costs, and the cost of capital have been examined independently to assess the sensitivity of the economic analysis to their movements. The outcome is summarised in Part 5.3.4.

No allowance has been made for cost inflation.

5.3.1 Cable and Line Cost Variation

As already mentioned in the report, the costs of supplying and laying of the cables (including any route deviation and burial) are very difficult to determine at this stage. To provide an indicator of the impact of cost changes, capital costs used in the basic analysis were increased by 30% and decreased by 15%. The latter value has been included in case the contingencies applied in the scheme costing are not fully used.

For the overhead lines, these same factors have been applied to cover routing and design variations, even though the effect on overall scheme costing is small.

The converter station costs represent only about 20% of scheme costs. Consequently, with a competitive manufacturing market and proven technology, the likely effect of changes in costs, as a percentage of total scheme cost, is expected to be small. Converter station cost variations have been neglected therefore.

For a 30% increase in cable and line costs, the break-even cost of the Icelandic energy supply will decrease to 9.4 mills/kWh (i.e. by 33%).

For a 15% decrease in cable and line costs the corresponding break-even cost will increase to 16.6 mills/kWh (i.e. by 17%).

5.3.2 UK Generation Cost

With all other factors unchanged, the total cost of generation in the UK was increased and decreased, arbitrarily, by 20% and 10% respectively.

For a 20% increase in cost, the break-even Icelandic supply cost increased by a substantial amount (46%) to 20.7 mills/kWh, indicative of the fact that the NPV of the displaced UK energy cost is roughly twice the NPV of the HVDC scheme costs; the break-even cost of Icelandic generation reflecting this difference.

A 10% decrease in cost of UK generation would require a decrease in the Icelandic supply cost to 10.9 mills/kWh (i.e. by 23%).

5.3.3 Discount Rate

By applying discount rates of 12% and 8% to the annual values of expenditure, the following break-even costs for Icelandic generation were obtained:

For a 12% rate, the cost could increase to 15.4 mills/kWh (i.e. by 8%)

For an 8% rate, the cost would be forced down to 13.7 mills/kWh (i.e. by 4%)

Consequently, a higher interest rate would increase the schemes viability.

5.3.4 Summary of Sensitivity Study

Table 5.4 below summarises the outcome of the study. Although both increases and decreases in parameters have been examined, it is more likely that cable and line costs and UK generation costs will increase rather than decrease. In addition, a scheme such as this is more likely to involve interest charges that are higher than 10% pa.

Table 5.4
Sensitivity Analysis

Variable		Break-even Icelandic Generation Cost	
Entity	Variation (%)	Result of Variation (mills/kWh)	Change to basic study value of 14.2 mills/kWh (%)
Cable & Line Cost	+ 30 - 15	9.4 16.6	- 33 + 17
UK Generation Cost	+ 20 - 10	20.7 10.9	+ 46 - 23
Discount Rate	+ 2 (to 12%) - 2 (to 8%)	15.4 13.7	+ 8 - 4
Base Value	No Variation	14.2	0

The most significant conclusion to be drawn from this analysis is that relatively small increases in UK base load generation costs will have a substantial impact on the corresponding break-even cost of generation in Iceland. Consequently the HVDC scheme will be much more attractive, financially, should UK generation costs increase. Some of this advantage will be offset, of course, if the cable and line costs increase.

Further comments on the impact of the sensitivity analysis on the concept of the scheme are made in Part 6.5.

6. OVERALL ASSESSMENT

To facilitate overall assessment of the scheme, an attempt is made in the following sections to outline the technical, financial and economic aspects of base load supply of 2000 MW from Iceland to the UK.

6.1 Supply Security

As stated in Part 3.4, there appears no justification for providing spare cables to cover the times of cable repair outages. It is expected that the HVDC supply can be classified as 'firm' and UK system spinning reserve will be provided to cover the loss of a bipole or cable pair, i.e. 670 MW. This value corresponds approximately to the largest standardised turbo-generators now employed in the UK. The likelihood of breakdown of more than one cable circuit is sufficiently remote that it is not justified to cover this by an additional spinning reserve margin.

While high reliability and availability of HVDC conversion equipment and overhead lines are relatively well established, the same does not apply to unburied undersea cables. In particular, the routing between Iceland and Scotland will be onerous and fears must exist about diminution of security through damage by fishing and geophysical events. Cable burial will provide the only reasonable form of protection in the worst areas. Not enough is known of the extent of exposure to risk of damage to permit making a reliable assessment of availability. Only a route corridor survey and detailed analysis of fishing patterns and sea-bed data will permit this assessment. This report has assumed, nevertheless, that a substantial amount of cable burial will be required.

Should the proposed scheme be accepted, it is likely that cable repair facilities and personnel would always have to be on standby to ensure outage times are kept to a minimum. The most important feature would be the locating of a suitable repair vessel, possibly at the mid point (Faeroes), for the duration of the scheme. For this reason, the entire cost of a new ship has been charged to the scheme. This requirement would be mitigated when sea bed habitats are available for in-situ repairs.

The installed generation capacity in Scotland is likely to be increased in the early 1990's by the establishment, by NSHEB, of a pumped storage scheme just north of Glasgow. The Craigroyston scheme near Loch Lomond is still in the long-term planning stage and public enquiries on the environmental effect of the scheme have not yet been arranged. The proposed initial and ultimate capacities of 1600 and 3000 MW approximately would complement the base load capability of an HVDC input. However, EHV system security would only be improved for short duration outages, such as with converter station faults, and negligible cover would be provided for extended sea cable outages.

6.2 HVDC Scheme Viability

The HVDC scheme appears technically viable, even though some development work should be expected for cable tensile strengthening and cable laying, burial and burial surveillance.

In the late 1980's there could be scope for displacement of UK base-load generation by such an HVDC scheme. Some of the problems foreseen would include:

- acceptance of an energy input which would displace activities from the UK power manufacturing and energy supply markets. The deleterious effects on short and long term employment could be unpopular

- a further input of electricity to a system which has already a surfeit of generation capability (i.e. a spare plant margin of around 35% at present)

- lack of opportunity for reciprocal energy exchanges, so the benefits of diversity, reduced total plant requirements and mitigation of operating problems cannot be realised to the extent possible with an exchange scheme

- doubts about the security of a 1000 km undersea transmission link may exist until more performance data on comparable schemes is collected

- overhead HVDC lines would need to traverse about ¾ of the length of Scotland. Transmission line way-leaves are difficult to obtain and a link such as this could meet strong environmental objections.

On the other hand, the HVDC scheme could provide advantages, apart from the relative cheapness of delivered energy

- the displacement of fossil fuel burning or reactor powered generation would be attractive to environmentalists.

- one less large power station site would be needed. With the current generation programme, problems are being experienced in obtaining new sites. A converter station is expected to present less of a problem

- construction and fuel handling costs for nuclear stations could increase substantially if more stringent safety requirements are called for by the UK nuclear licensing authority (NII)

- the export-orientated industries associated with converter equipment and cable design and manufacture would be boosted by the involvement in a scheme of this magnitude and complexity. In fact, the involvement of British industry in the design, manufacture and construction can be expected to be a prerequisite for scheme acceptance

- an electricity source with a negligible 'fuel' cost content would provide a counter to ever-increasing coal, oil and nuclear fuel costs.

6.3 Financing

The division of financial responsibility for an electrical interconnection between the power systems of two countries normally follows the principle that each country bears the costs within its own territory and up to the common boundary. For marine crossings, the boundary can be taken generally as midway between the shore lines. For this HVDC scheme the boundary could be in the vicinity of the Faeroe Islands, i.e. approximately equidistant from Iceland and Scotland.

Half the capital expenditure for the transmission link, which would be approximately $ 1300 million based on current costs, would be within the normal capital appropriation for increasing the generating capacity in the UK. It may be assumed therefore, that the funds required for the UK part of the scheme could be procured from governmental sources in the usual way.

For Iceland, on the other hand, the investment requirements would be likely to exceed the normal financing capability of the public electricity supply. It would be necessary, therefore, to investigate alternative sources of funds. Additional and concurrent expenditure on a major hydro scheme in Iceland would be required also to provide the energy source for the HVDC transmission.

International financing agencies, such as the World Bank or the European Investment Bank, are unlikely to fund the whole of the expenditure. Some partial financing by such agencies appears possible, however, as the HVDC scheme would undoubtedly promote the economic development of the country. Consequently, balancing loans from other sources would be required. Loans from commercial sources appear unattractive for a scheme of this nature because interest rates would be high and loan lives relatively short.

Tied loans provided by the country or countries supplying the equipment appear more promising. These loans are often made available at relatively low interest rates, such as 6 to 7½%

currently, and loan lives can extend to about 25 years. A general condition of such loans is that the equipment for a scheme should be purchased from the country providing the loan.

While the complete cost of the hydro scheme would have to be borne by Iceland, there should be scope for negotiations with regard to the proportions of HVDC scheme expenditure to be shared between the countries. One advantage in having a large UK share in the supply and installation of converter stations and cable is that loan capital could be acquired in the UK at a rate of interest which could be lower than that available to Iceland which, it is understood, has no facilities to design and manufacture the plant. Substantial UK involvement in the scheme is likely to be more acceptable than total Icelandic involvement.

More research will be necessary before the possibilities of financing the scheme are clear, but there is little doubt that the sums of money in question could be found on reasonably attractive terms.

6.4 Pre-Project Expenditure

This scheme, which pushes undersea cable technology to the present limits and involves the expenditure of very large sums of money, must entail a substantial amount of spending on investigation and development work before the project is undertaken. The two major facets of the investigation into the feasibility of the scheme would be:

- a cable corridor survey to assess possible routes and examine sea bed conditions; at a cost of approximately $650,000

- a network analyser study of the HVDC and EHV systems; at a cost of approximately $800,000

These costs, together with the individual cable route survey costs, have been included in the economic appraisal of the scheme.

Existing cable-making facilities are likely to require considerable expansion to cope with a project of this size. It is possible, therefore, that funding of factory extensions will be required. An estimate of such capital input in the early stages of the scheme has been included in the economic analysis in Part 5.2.

Expenditure would be required on development work related to cable laying and burial. The extent of this expenditure can be determined only after more precise knowledge of the cable route is obtained. It is possible that techniques developed for the laying and burial of pipes to oil/gas fields in the North Sea can be of use.

6.5 Scheme Economics

It has been shown that, based on current costs, an HVDC scheme would be economically viable if the Icelandic electricity supply to the AC busbars of the rectifier station could be provided at a cost below 14.2 mills/kWh. This study does not include an analysis of the feasibility of hydro generation in Iceland being able to produce electricity below this cost.

The sensitivity analysis has highlighted interesting aspects. Percentage changes in cable and line costs produce almost equal percentage changes in the necessary hydro generation cost, but UK base load generation costs and changes in the discounting rates have a very considerable effect on the hydro 'break-even' value.

It should be noted in particular that as UK generation costs increase in real value terms, which they are likely to do, the attractiveness of the HVDC scheme will improve rapidly.

DEFINITION OF TERMS

Forced Outage

A breakdown resulting from operating conditions directly associated with an item of plant, such that the item must be removed from service as quickly as possible

Scheduled Outage

An outage resulting from the pre-arranged removal from service of an item of plant; the removal being due to maintenance, repair, construction or testing

Unavailability (U)

$$U = \frac{MTTR}{MTTR + MTBF} \times 100\%$$

where MTTR is mean time to repair
MTBF is mean time between failures
(or reciprocal of failure rate)

Availabiltiy (A)

$$A = 100 - U\%$$

Average System Availability

Availability of converter, line and cable allowing for forced outages only. It covers only those periods when the plant is in operation.