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The National Energy Authority of Iceland

REPORT
ON HVDC TRANSMISSION

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

Virkir
Associated Engineering
Consultants Ltd.
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SUMMARY

This report discusses the merits and technology of HVDC power transmission using overhead lines and submarine cables. The main applications of HVDC are highlighted by reference to schemes already operating around the world.

Economic and technical appraisals have been carried out on two potential HVDC projects. The first project examined the economic merits of transmitting 1, 000 MW by HVDC, instead of AC, a distance of 400 km overland. In this case it is not economic, as the distance is too short for the savings, derived from using HVDC overhead transmission lines, do not compensate for the high cost of conversion from AC to HVDC.

The second potential project examined the economics of bulk HVDC transmission of 2, 000 MW by submarine cable, over a distance of 900 km. To make this a realistic study it is assumed that the power is exported to Scotland and the delivered HVDC energy must be competitive with nuclear energy in Great Britain. The scheme is technically feasible if it is possible to find a cable route between Faroes and Scotland that keeps to a depth of less than 1, 000 metres. For there to be no doubt on the economic feasibility of the project the energy must be provided in Iceland at a cost of 7 mills/kWh. If it is above 7 mills/kWh but below 16 mills/kWh more detailed economic studies would be required that take into account intangible benefits.

1. INTRODUCTION

1.1 Terms of Reference

The National Energy Authority of Iceland requested Virkir Associated Engineering Consultants in co-operation with Electrowatt Engineering Services Limited to prepare a report on HVDC transmission with the following Terms of Reference:-

1. Discussion of the present technology of HVDC power transmission, both overland and submarine.

2. Preparation of an economic comparison of overland bulk transmission of 1,000 MW and 8,000 Gwh/yr over a distance of 400 km by conventional AC and HVDC.

3. Preparation of an economic evaluation of HVDC submarine bulk transmission of 2,000 MW and 16,000 Gwh/yr over a distance of 900 km.

1.2 Comments on The Terms of Reference

In line with the Terms of Reference, the report is divided into three main sections. Section 2 gives an appraisal of EHVAC to HVDC conversion technology and HVDC transmission using overhead lines and submarine cables. Also, there are sub-sections on the characteristics and applications of HVDC transmission. Section 3 examines the overland bulk transmission of power and Section 4 examines the transmission of power by long-distance submarine cable.

It is assumed that the overland bulk transmission schemes can be carried out in the early 1980's whereas the submarine transmission scheme cannot be carried out until the late 1980's. The reason for the difference in timing is because the technology for the overland bulk transmission scheme is well established and its timing would be dependent on the development of the demand and the power source. In the case of the submarine cables, a large amount of development work would be required as the cable route is nearly eight times longer and in depths greater than any other HVDC submarine cable route now existing in the world. Another reason is that the country receiving the power would not be able to incorporate a power source of 2,000 MW into its generation development programme before the mid to late 1980's as the new generation planned for early 1980's is committed already.

Apart from technical reasons, the main economic reason for choosing HVDC, in preference to AC, is that the cost savings derived from using HVDC transmission, instead of AC transmission, outweigh the extra cost of conversion from AC to HVDC.

No details of the source of power in Iceland has been given. Some assumptions have had to be made with regard to the type of power, the size of units, their location or timing and these are stated in the appropriate places in Sections 3 and 4. In fact, the purpose of Section 4 is to determine the price at which the energy from the power source must be generated to make it competitive with base load nuclear generation, if transmission to Great Britain is to be considered. Unless there are unforeseen changes in the pricing policies of oil from the North Sea or strong environmental pressures against nuclear generation, all new base load plant to be installed in Great Britain in the mid to late 1980's will be nuclear. Therefore, as long as the load factor of the power source is greater than say 70%, it must displace base load generation which is nuclear.

1.3 Economic Assumptions

It is assumed that the opportunity cost of capital in Iceland is 10%. This 10% test discount rate is the same value as that applied by the nationalised industries in Great Britain for their economic assessments and it is used in this report for all economic comparisons.

The base date for all cost estimates in this report is the 15th January 1975. The exchange rates which were used are given in Table 1.1 below:

TABLE 1-1

Exchange rates used for preparation of cost estimates, for £1 sterling

U.S. $	2.354
Swedish Kroner	9.612
Icelandic Kroner	274.25
Swiss Francs	6.045

These rates were applicable on 15th January 1975.

2. APPRAISAL OF AC/HVDC TECHNOLOGY

2.1. The Basis of AC/DC Conversion

The practical development of HVDC stems from the availability of static switching elements, at first the mercury valve and latterly the thyristor. In DC transmission terminology, the word "valve" means any single branch of the power circuit having the property of unidirectional conduction, the start of which can be inhibited by a control signal. The mercury device and the equivalent single phase assembly of thyristors are referred to as valves.

2.1.1 Basic Systems

The simplest basic AC-DC converter system consists of:

A converter transformer which transforms the network voltage to the HVDC transmission voltage and isolates the AC system from the DC system. It also provides a means of voltage control.

A six-pulse converter bridge using thyristors or mercury arc valves to convert AC power to DC.

A control system to initiate and control the firing angle of the valves.

A DC reactor to smooth the direct currents.

The basic arrangement is shown in Figure 2.1.

The AC voltage having the highest value in either polarity is connected by the appropriate valve to the DC terminals. In any one period of the AC system there are six output voltage peaks as shown in Figure 2.2. The output DC voltage has a ripple waveform and its magnitude is nearly equivalent to the AC peak value. The flow of current between the AC and DC sides during two of the six stages in a cycle is illustrated in Figure 2.3 together with the voltage diagram which shows the phase to neutral voltages in each of the transformer phases. The thick black line shows the two conducting phases. Commutation of the current from one valve to the next in the same row takes place automatically at the cross-over points of the voltage curves.

With a control system it is possible to delay the start of conduction through a valve. The phase which is already conducting will continue to do so following the voltage sine wave until the next incoming valve is triggered off. Figure 2.4 shows the effect of increasing the commutation delay. As the delay "α", measured in electrical degrees, is increased the mean DC voltage is proportionately decreased down to zero when $\alpha = 90^{o}$. If the delay is now further increased towards 180^{o} (in practice 160^{o}), the mean voltage becomes negative, i.e. reversed, but the current still flows in the same direction so that the power flow is reversed and the converter now operates as an inverter converting DC into AC.

Therefore by adjusting the firing angle of the valve the ratio of mean DC volts to AC volts can be smoothly changed from a maximum positive value down through zero to a maximum negative value. For a low firing angle the power flow is from AC to DC, (rectification) and for a high firing angle the power flow is from the DC to the AC system (inversion).

The simple circuit illustrated in Figure 2.1 is very much more complicated in practice, due to the harmonics which exist in any cyclic switching system. The DC voltage and AC currents have substantial harmonics contents. On the DC side there are 6th, 12th, 18th; ---6 nth orders and on the AC side the corresponding harmonic pairs are 5th and 7th and 13th up to $(6n \pm 1)$th order.

To reduce these harmonics down to an acceptable level, so that interference with the telecommunications systems and losses are minimised, filter equipment is required to be added to the circuit shown in Figure 2.1. Normally the AC filters are shunt connected and typically comprise 5th, 7th, 11th and 13th series resonant acceptor circuits with a damped bandpass section for higher harmonics.

If the valve is a mercury arc rectifier, resistance-inductance and capacitance-resistance damping components will be required, on the DC side, to control the transient oscillations excited in the main power circuit at instant of switching. Thyristor valves, on the other hand, do not require external damping circuits as the damping circuits are built into the valve itself. The components are physically distributed alongside each thyristor element together with the gate control circuits.

The capacitance of the filter equipment partly compensates for the inductive load which the converter throws on the AC system. Further MVar generation and a fast control system will be needed to prevent undue variation of AC voltage. If the rectifier end is close to the supply generation, the alternators can supply the extra MVars required. At the inverter end some other source of MVar generation is required either in the form of a synchronous compensator or a static device such as saturated reactor, and shunt capacitor, with a step down transformer.

2.1.2 The Thyristor Valve

As the valve is the most important part of the AC/DC conversion process, it is worth examining in a little more detail. In recent years the trend in HVDC transmission has been to move away from mercury arc rectifier valves to solid state thyristors. The thyristor valve is completely free of arc back phenomenon, which was one of the drawbacks of mercury arc rectifiers, and this gives the converter station the ability to make rapid changes in load level. This facility enhances the dynamic performance of the power system. Another advantage of the thyristor system is that the physical area required for the converter station is very much smaller than with the mercury arc rectifier system as the thyristors do not require external damping filters.

The thyristor has relatively simple auxiliary circuits and is therefore employed in series connected stacks, with voltage grading enforced by tapping the individual thyristors across a capacitor and resistor divider formed from the damping circuits.

As series connected elements are identical, the basic problem of poor voltage division during propagation of the conducting phase of the medium is avoided at the cost of the circuit complexity. Many auxiliary components are required with each thyristor - these include inductors, capacitors, resistors, heat sink and electronic control equipment but they are enclosed in the thyristor module.

Complete valves of any rating can be built by using adequate numbers of series/parallel thyristors. The rating of an individual thyristor is only important in the sense that it reduces the total number of thyristors required in a valve and therefore reduces cost. Also the rating of a valve is determined by the need to withstand transient overvoltages and currents rather than by conditions at normal full load.

The design of the valve is such that redundancy is built in and the failure of a few thyristor modules would not stop the valve operating. If a thyristor in a valve or an assembly group with two or more parallel thyristors fails, the defective group forms a conductive connection after the loss of blocking capacity. If a sufficient number of redundant reserve groups are provided in the valve, e.g. 5 to 10% more than would be necessary in respect of valve voltage, such failures do not impair the reliability of the valve, provided the built-in redundancy has not been used up. From the valve rating and design, the failure rates of its components and the proposed redundancy it is possible to determine the probability of the maintenance-free period of a valve over a period of years.

In a mercury arc valve converter station the major part of maintenance is attributable to the valve. The thyristor valve with its built in redundancy and solid state control equipment requires negligible maintenance which means the moving parts in the auxiliary equipment such as fans and pumps dictate the shutdown time necessary for maintenance. This can be as little as 24 hours per year.

2.2 HVDC Submarine Cables

2.2.1 Design Considerations

There are three types of cable which are used for HVDC transmission. These are the oil-filled paper insulated cable, the gas-filled pre-impregnated paper insulated cable and the impregnated paper insulated solid type.

Cables have to be designed to withstand electrical and mechanical stress. The main stresses which have an influence on the design of the cable are described below:

Electrical Stress

(a) Working Voltage Conditions

The ability of the dielectric to withstand a steady DC voltage is the basic requirement for a DC cable. Under direct voltage the stress distribution in the cable dielectric and the dielectric strength are controlled by mechanisms different from those applicable to AC cables.

In the steady state the stress distribution in a DC cable is controlled by the conductivity of the dielectric. The short-term DC strength of fully impregnated paper dielectric is of the same order as the impulse strength 90 - 100MV/m which is at least three times the normal working stress.

In order to guarantee satisfactory performance of the cables in service the life of the dielectric, i.e. long-term DC strength, is much more important. Oil-filled and gas-filled type cables differ substantially from the non-pressurised solid type cables. A serious limitation on conductor temperature is imposed on a solid cable by drainage of impregnating compound from the gaps of the paper insulation and this makes the behaviour of the dielectric uncertain. The ageing process due to partial discharges is a primary factor in determining the life of a solid type cable and a service stress above 25 - 30MV/m cannot be accepted without risk.

Oil-filled cable under DC operation is not subject to particle discharges so that the ageing process is similar to that of AC cables and tests have shown that a service stress of 35MV/m is acceptable. Gas-filled cables also do not suffer from this problem partly due to the pre-impregnated paper insulation, which is impregnated before the cable is manufactured, and the high gas pressure. The service stress the cable can be subjected to should lie somewhere between the stress ratings of the solid cable and the oil-filled cable.

(b) Transient Voltage Conditions

In DC cables sealing end flashovers or polarity reversals will set up transient stresses. For polarity reversals the rate of change of voltage will be less than that caused by sealing end flashovers. In specifying the transient overvoltage conditions for DC cables, the surge magnitude is the primary factor but the waveshape must also be taken into account.

Sealing end flashover would produce a steep front travelling wave of short duration. Local stress would be produced and the presence of oil gaps in the insulation would determine the dielectric strength.

Polarity reversal takes place when the direction of power flow is reversed. This produces a relatively slow transient and the dielectric strength is controlled by the normal stress distribution. International specifications lay down a polarity reversal test carried out at a voltage 1.5 times the working stress immediately after reversal takes place.

Oil-filled and solid type cables do not appear to be limited by this type of transient, but for gas-filled cables the polarity reversal test may control the design stress. In the project under consideration the power flow will always be in one direction so this limitation on gas-filled cables may not be so important.

Mechanical and Thermal Stresses

In the case of submarine cables mechanical stress is a very important consideration in the design of the overall cable as they are subjected to severe mechanical stresses during the laying or recovery processes. These are due to the weight of cable and the depth of water the cable is being laid in and the resulting pressures exerted by the laying machine on the cable.

A further important factor to be taken into consideration is the friction coefficient between the paper tapes and between the armour and the reel of the laying machine. These must be matched as closely as possible, otherwise relative movement between the armour and conductor may occur which could result in displacing the paper tapes and reducing the dielectric strength.

The most critical strains on the lead sheath during the normal operation of a submarine cable layed at great depths are due to thermal expansion and contraction of the impregnating compound caused by load variations. It has been proved that if the load on impregnated solid type cable is suddenly switched off a dangerous situation develops during cooling. In these conditions the cable insulation may suddenly break down within a specified time interval from the beginning of the cooling period.

Site Factors

The design of a specific submarine cable for a project has to take into account the following site factors:

1. Depth of water the cable is laid in; this determines the external pressure on the cable which it must be able to withstand without deformation. In the case of gas-filled cables it also determines the gas pressure required to stop the ingress of water in case of fault.

2. The nature of the sea bottom and currents on the sea bottom. Sea bed rocks and currents may produce bending or abrasion if there is any cable movement on the sea bed.

3. Wave and breaker action at the shore ends may also cause cable movement and associated abrasion.

4. Maximum water temperature which will determine the temperature gradient between the conductor and outside sheath. The temperature gradient will influence the final current rating of the cable in order to maintain thermal stresses within acceptable limits.

5. Weather conditions in relation to cable installation and where required the carrying out of jointing operations at sea. Even if jointing operations at sea are not required during the actual installation of the cable they may be required at a later date if a fault develops on the cable.

6. Marine borers.

7. The length of route in relation to voltage generated across the anticorrosion sheath between the reinforced lead sheath and the armour by travelling waves on the conductor. To keep these voltages below the electric strength of the anticorrosion sheath, the armour and lead sheath must be short-circuited at intervals.

2.2.2 Construction of Submarine Cables

Although due to their higher dielectric strength, oil-filled cables are more economical for overland use and very short submarine cable routes, they cannot be used for long distance submarine cable routes. This is because oil-filled cables can only be manufactured in short lengths and the cable would have to be jointed on board ship for long stretches, which is undesirable. The other main objection which rules out oil-filled cables is the problem of maintaining the required oil pressure.

As oil-filled cables can be ruled out on account of length alone, gas-filled and solid paper cables are considered further.

Gas-filled Cables

Gas-filled cables have been successfully used in the Cook Straits crossing which connects the North and South Islands of New Zealand. An illustration of the type of cable used for this crossing is shown in Figure 2.5.

The characteristics of gas-filled cables are as follows:

1. The cable can be made in continuous lengths.

2. The paper insulation is preimpregnated before manufacture of the cable. Because the paper dielectric needs to contain no free impregnating compound and is under gas pressure, there are no changes in dielectric quality during the life of the cable.
   Furthermore, no mechanical problems arise with lead sheath distention during thermal cycling.

3. The metal tapes which reinforce the lead sheath against the internal gas pressure also serve as "antitwist" tapes which are very desirable with any heavy armoured cable laid in deep water. They also support the cable against deformation under external water pressure.

4. Gas pressure, preventing water entry, can be maintained if the lead sheath is damaged or during repair operations.

5. The gas pressure brings about a significant increase in electric strength, particularly when compared with a mass impregnated cable after prolonged service.

Further study would be required to confirm that the gas pressure could be maintained over the half route lengths required for the Iceland-Faroes-Scotland project. If a landing is made on the Faroes the half route length would be 250 km. If the pressure could not be maintained over this distance then the choice of cable would be limited to the solid type cable.

Solid Cables

The majority of HVDC submarine cable crossings in operation use solid cables. Figure 2.6 illustrates a typical solid cable which is to be used in the further development of the Konti-Skan scheme between Sweden and Denmark. The overall diameter is 108 mm and it weighs 30 kg/m. The largest HVDC cables being developed at the moment are for the crossing of the Skagerrak Sea between Norway and Denmark. The cables are planned to be laid in 1976 and 1977. They will be the longest submarine cables in operation (130 km) and they will be laid in a greater depth (up to 550 m) than any other HVDC submarine cable. Each cable will be rated at 250 kV, 1,000 amps and be capable of transmitting 250 MW.

Extensive development work has been carried out on the design of both the cable and flexible joints. As there is a lot of trawling in the Skagerrak Sea the cable requires to be heavily armoured and the finished cable will weigh approximately 50 kg/m.

It was decided that it would not be economic in this case to design equipment to manufacture the cable in one continuous length and instead it was decided to make the cable in shorter lengths and join them together on the quayside with flexible joints before loading on board ship. The cable will be laid in one continuous length.

2.3 HVDC Overhead Lines

There are basically two types of overhead lines; monopolar or bipolar. With a monopolar line the return path is either via earth or another monopolar line. Typical towers for a 375 kV monopolar line and a $\pm$ 375 kV bipolar line are shown in Figure 2.7. For a comparison, an AC 400 kV tower is shown. The DC towers are latticed galvanised steel towers with concrete block foundations and the construction is similar to conventional AC towers. The design of the DC towers and lines have to take account of similar external loading conditions and safety factors as the AC lines.

The main advantage of HVDC lines is that only two conductors are required instead of six for a double circuit line. Also for a given level of insulation a DC line can operate at a higher voltage than an AC line. The insulation required for an AC line is determined by the switching surges that occur in the system during circuit breaker operation. This can be up to $2\frac{1}{2}$ times the normal rated voltage. With DC the determining factor is the operating voltage which in turn determines the length of the leakage path on the insulators. Another important advantage is that the visual impact of two monopolar lines set a reasonable distance apart or even a bipolar line would be very much less than the double circuit AC line due to the difference in height and reduced number of conductors required.

2.4 Characteristics of HVDC

Sections 2.1 to 2.3 describe the operation and main items of equipment used in HVDC transmission. This section examines the advantages, disadvantages and characteristics of HVDC transmission compared with AC transmission.

In Section 2.1, it is seen thatan HVDC converter station is much more complicated than a straight-forward AC transformer station and this in turn makes it more expensive and less reliable. To set against the extra cost and lower reliability of the converter station is the saving on the cost of HVDC transmission lines and cables and certain technical advantages which will be discussed below.

A DC line is more economical than an AC line of the same transmission capability as it can be better utilized with respect to voltage and current. Only one conductor is required if an earth return is used compared to three for an AC line. Consequently fewer insulators are required, supports are lighter and the ground width of the tower base is smaller. As shown in Section 2.3, the lower height of a DC line compared to an equivalent AC line reduces the amenity impact.

The smaller number of conductors and associated insulators will result in a lower fault incidence rate compared with an AC line. If a fault should occur on one conductor the supply can be maintained by using earth return which is not practical with an AC line. The costs of the earth electrode are insignificant in comparison with the cost of one long distance overhead line. If the thermal rating of the healthy conductor allows, and parralleling of converters in the stations is foreseen, the earth return can carry almost the full transmission power. To afford equivalent security of supply with AC lines two circuits would be necessary.

The DC line needs no shunt or series compensation and presents no stability problems whereas with a long distance AC transmission line there may be stability problems and it may be necessary to install equipment at the receiving end to maintain the voltage. If it is required to supply a number of points along a transmission route AC will be more economical than DC due to the high cost of the converter equipment.

For economical underground power transmission circuits a 3 phase AC system is not the best. A DC cable system is much better since the conductor losses are lower, there are no dielectric or sheath losses and with no sheath standing voltages, no need for cross bonding. With a three cable array (AC) the middle cable must run hotter than the other two whereas with a two cable bipolar DC array both cables will run at the same temperature.

A major advantage of a DC cable system is the more efficient utilisation of insulation. For a given size of cable the electric stress is three times as high as in the equivalent AC cable. This is due to the fact that the insulation is not heated by dielectric losses and owing to the absence of skin effect the conductor cross section can be fully utilized. This means for a given size of cable the transmission capability of a DC cable is three times that of an AC cable.

For long distance AC cables a large charging current is required which considerably reduces the power transfer. This must be satisfactorily controlled to obtain maximum utilisation of AC cables.

For long distance transmission AC cables would need voltage compensation equipment along the route and this would be impossible for long distance submarine cables.

When there is a fault on a DC cable security of supply is the same as in the case of DC overhead lines. Where an earth return is not permissible because of the risk of corrosion or interference with other services as is the case of the Kingsnorth-Beddington DC Scheme (London) a neutral conductor insulated for a low voltage can be provided. By contrast an AC transmission system would require a spare conductor insulated for the line voltage.

2.5 Application of HVDC

There are a number of HVDC schemes in operation or planned in different parts of the world. The reason for choosing HVDC in preference to AC is based on economic and technical factors some of which have already been mentioned in the preceeding paragraphs. Examination of these schemes will show that the choice of HVDC was made because the scheme fulfilled one or more of the following criteria:

1. Interconnection of asynchronous systems. Basically this means the ability to transmit power between two systems operating at different frequencies. Even if both systems had nominally the same frequency, it may be difficult to keep both system frequencies in step if an asynchronous link did not exist. The power transmitted is independent of both the frequency and the phase relationship of the voltages of the two systems.

2. Interconnection between systems involving long-distance submarine cable crossing. The reasons for HVDC have already been explained.

3. Long distance overhead line interconnection (say above 1,000 km). It has been shown that as the required standard of security of a system increases, the overhead line length required before an HVDC scheme becomes economic decreases.

4. Weak interconnection between two large systems.

5. Limited interconnection between transmission networks with the objective of containing fault levels. As the HVDC transmission system is basically operating with constant

current control, the DC current is limited to rated values even when disturbances occur in the AC systems. Hence, the DC link does not contribute to the short-circuit level in an AC system.

6. Large power reinforcement into a high-density city system involving extensive use of cables and/or containment of fault levels. The DC infeed to the city system could be at a lower voltage than would be possible with an equivalent AC power infeed since the DC infeed does not contribute to the short circuit level at the receiving end.

7. Rapid control.
The change of transmitted power on an HVDC line in response to a power change order from the control centre is almost instantaneous since HVDC does not involve any time-consuming constants or inertia. Fast-acting control can also be used for the dynamic stabilization of interconnected AC systems, especially if the DC link is operating in parallel with other AC interconnectors.
Figure 2. 8 shows the location of HVDC schemes in operation and also planned HVDC schemes.
Table 2.1 lists the schemes together with their main parameters and the reasons for choosing HVDC.
It can be seen from the Table that of the schemes listed (they do not cover all the schemes being considered in the world at this moment) all fulfil one or more of the above criteria. Eight out of the fifteen schemes involve submarine cable crossings. Four involve long distance overland bulk power transmission. There are two schemes

which provide asynchronous interconnection between two systems and the Kingsnorth Scheme in England will be the first scheme in the world to transmit bulk power from a power station to a densely populated metropolitan area via DC underground cables.

TABLE 2.1

PARTICULARS OF HVDC SCHEMES IN OPERATION AND PLANNED

Scheme	Map Reference No.	Commissioning Year	DC Voltage in kV	DC Current in Amps	Capacity MW	Length of overhead line in km	Cable Arrangement	Length of Cable in km	Main Reason for Choosing HVDC
Sweden - Gotland	1	1954-1970	+100 & +150	200	2,030	-	1 cable, earth return	96	Long Sea Crossing, frequency control
England - France	2	1961	±100	800	160	-	1 cable/pole	64	Sea Crossing asynchronous link
Volgograd - Dombass	3	1962	±400	940	750	480	-	-	Long distance transmission
New Zealand	4	1965	-250	1,200	600	575	1 cable/pole	42	Long distance including sea crossing
Sukuma, Japan	5	1965	2x (+125)	1,200	300	-	-	-	Rapid Control, low losses, asynchronous link 50/60 Hz
Konti - Skan, Denmark - Sweden	6	1965	+250	1,000	250	86	1 cable, earth return	87	Sea crossing, building in stages
Sardinia - Italy	7	1966	+200	1,000	200	290	2 parallel cables, earth return	116	Long sea crossing
Vancouver Island - Canada	8	1968-1970	+260	1,200	312	41	3 parallel cables, earth return	28	Sea crossing, building in stages, synchronous link in parallel with AC link
U. S. Pacific Intertie I	9	1970	±400	1,800	1,440	1,330	-	-	Long distance, rapid control. Operates in parallel with 500 kV AC intertie.
Eel River, Canada	10	1972	2x (+80)	2,000	320	-	-	-	Asynchronous link, rapid control to overcome stability problems
Nelson River - Winnipeg, Stage I, Canada	11	1972	+150, -300	1,800	1,620	895		-	Long distance transmission. Improved stability of associated AC network. Final development to be in excess of 6,000 MW.

TABLE 2.1

PARTICULARS OF HVDC SCHEMES IN OPERATION AND PLANNED

Scheme	Map Reference No.	Commissioning Year	DC Voltage in kV	DC Current in Amps	Capacity MW	Length of overhead line in km	Cable Arrangement	Length of Cable in km	Main Reason for Choosing HVDC
Cabora Bassa, Stage I, South Africa	12	1975	± 266	1,800	960	1,400	-	-	Long distance transmission. Final development 1,920 MW, in 1979.
Kingsnorth - London, England	13	1975	± 266	1,200	640	-	1 cable/pole 1 neutral cable	Kingsnorth to Beddington 59 Beddington to Willesden 25	Long underground cable, no increase in fault level at receiving stations
Skagerrak, Norway - Denmark	14	1976-1977	± 250	1,000	250	-	1 cable/pole	130	Longest and deepest sea crossing undertaken
England - France II	15	1980	2x (± 266)	1,800	2,000	-	2 cables/pole	60	Sea crossing, asynchronous link

BASIC 6-PULSE AC/DC CONVERTER SYSTEM

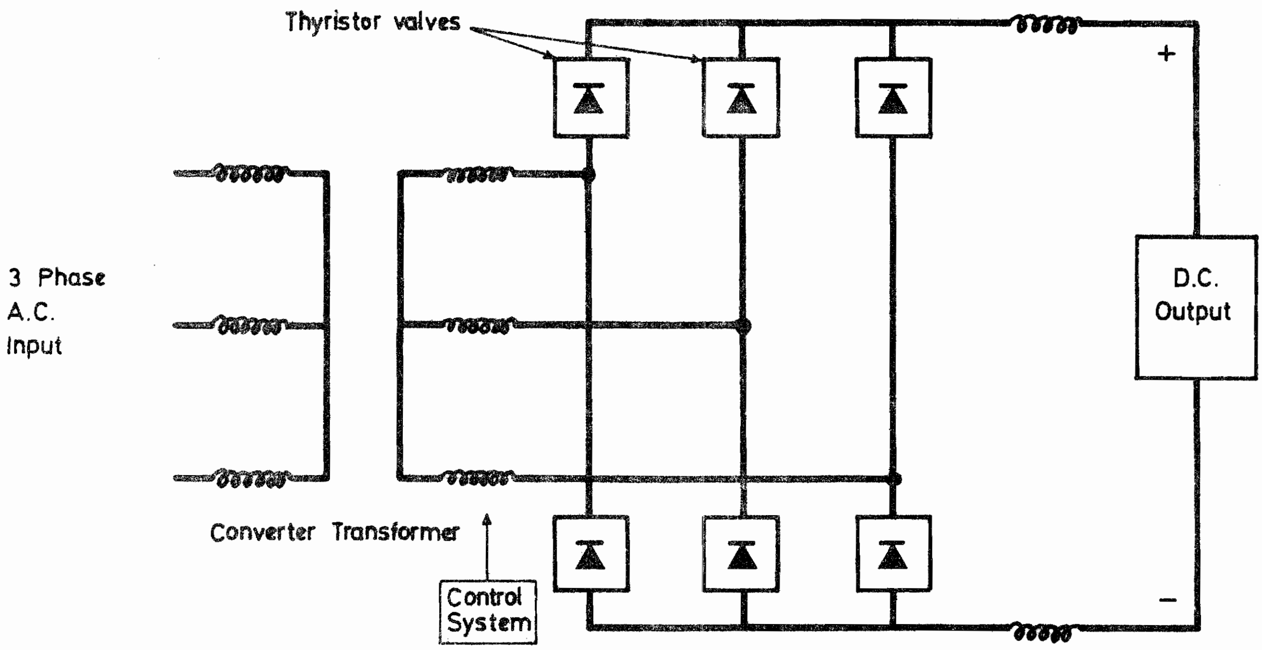
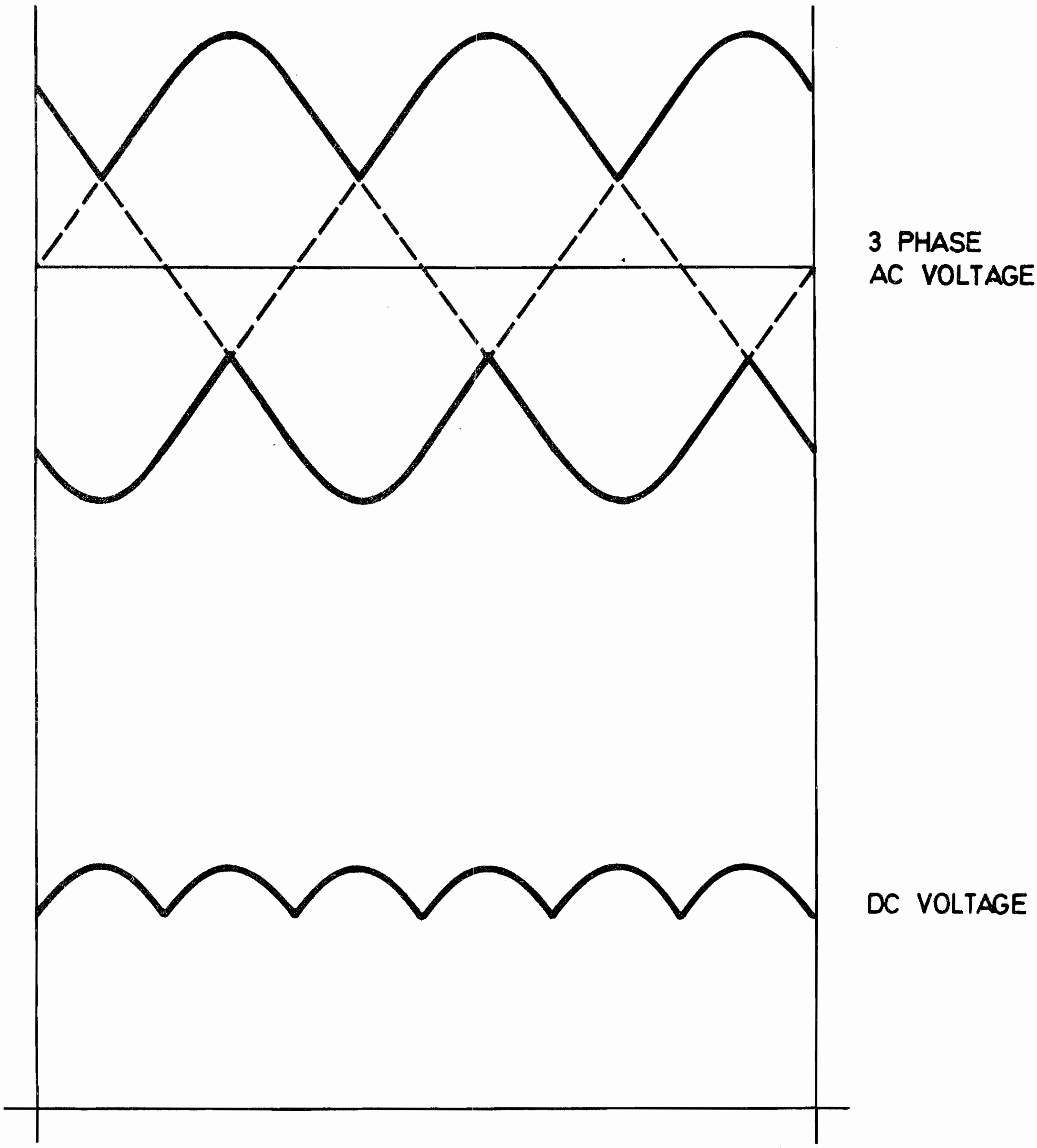


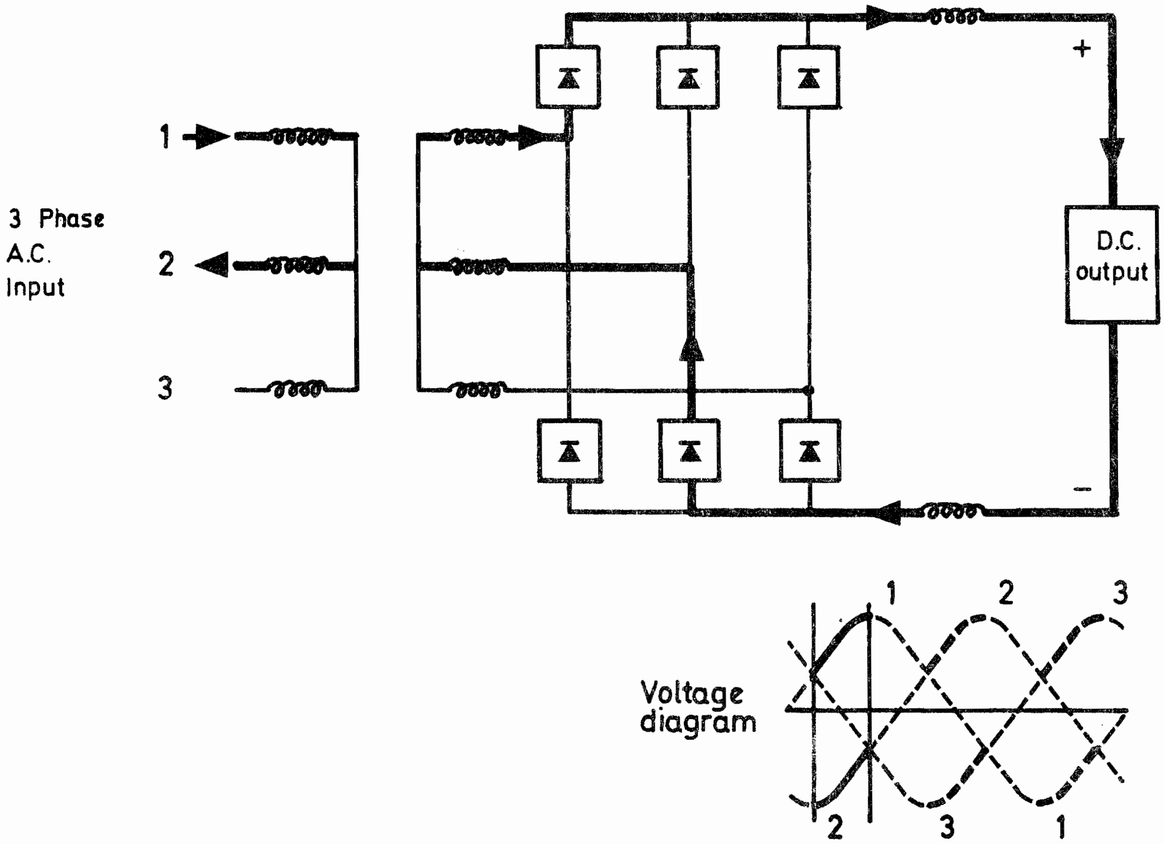
Figure 2.2

CONVERSION OF AC SINUSOIDAL VOLTAGE WAVEFORM TO DC



FLOW OF CURRENT IN CONVERTER EQUIPMENT AND VOLTAGE DIAGRAM

a) Flow of current in phases 1 and 2



b) Flow of current in phases 1 and 3

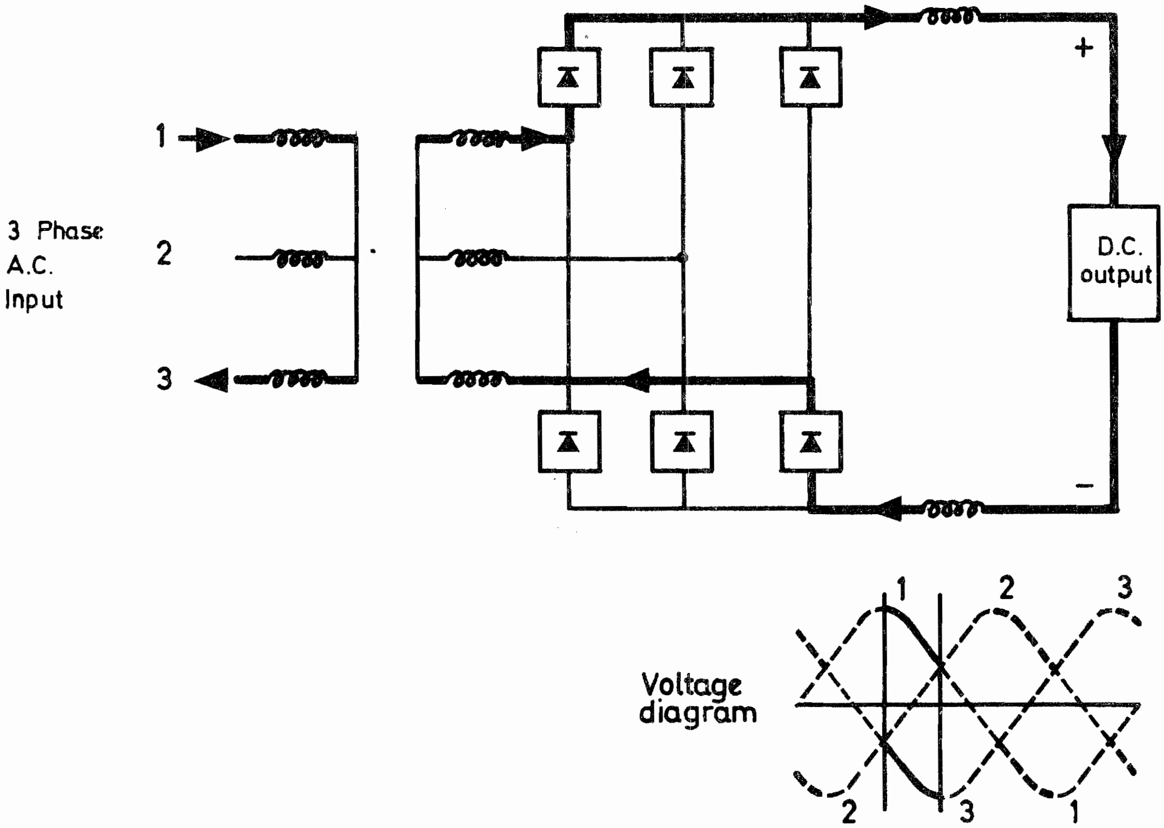
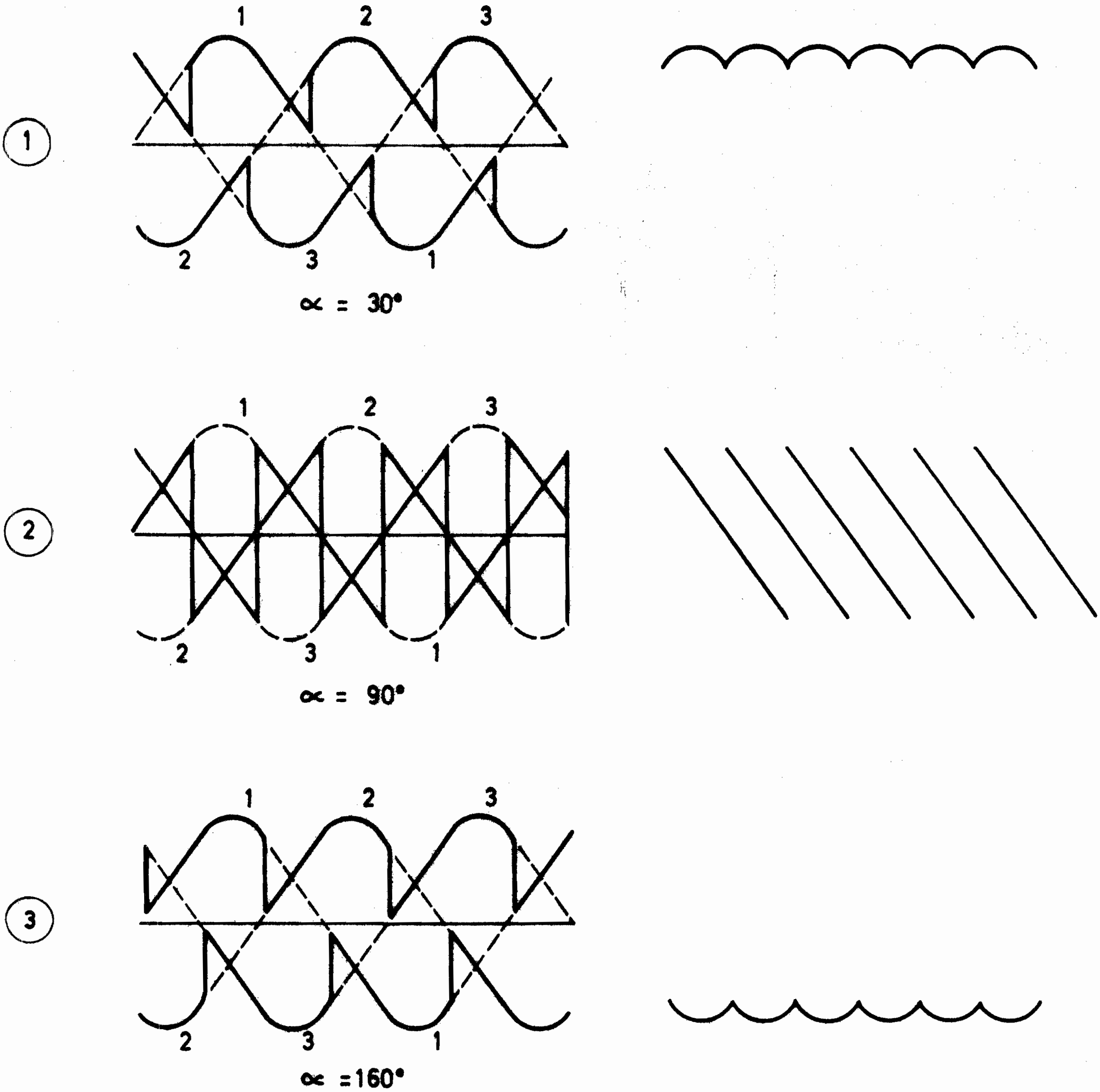


Figure 2.4

EFFECT OF INCREASING "α" THE COMMUTATION DELAY ANGLE ON THE DC VOLTAGE OUTPUT



AC input showing conducting phases

DC voltage output

TYPICAL GAS FILLED CABLE

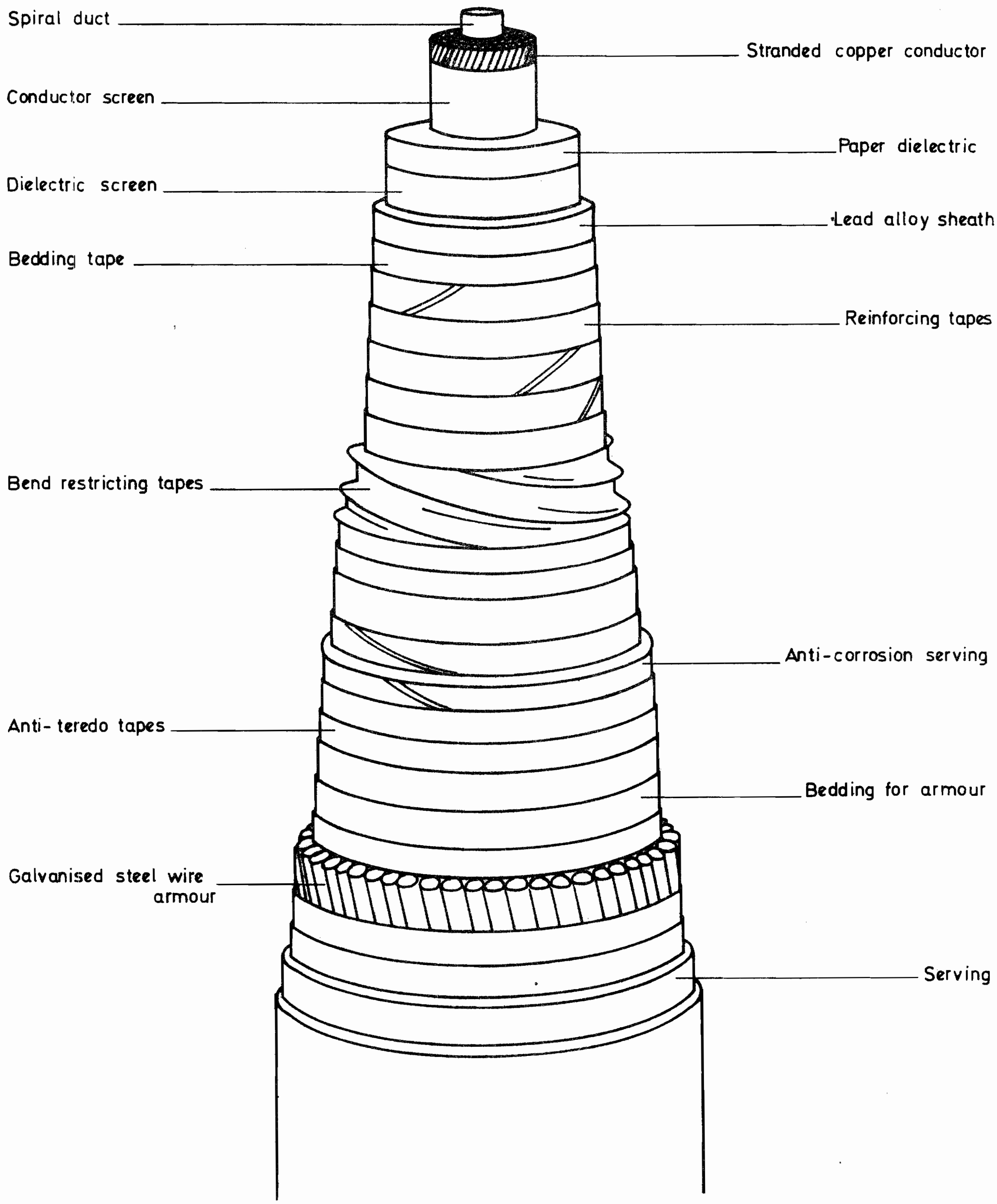


Figure 2.6

TYPICAL SOLID CABLE

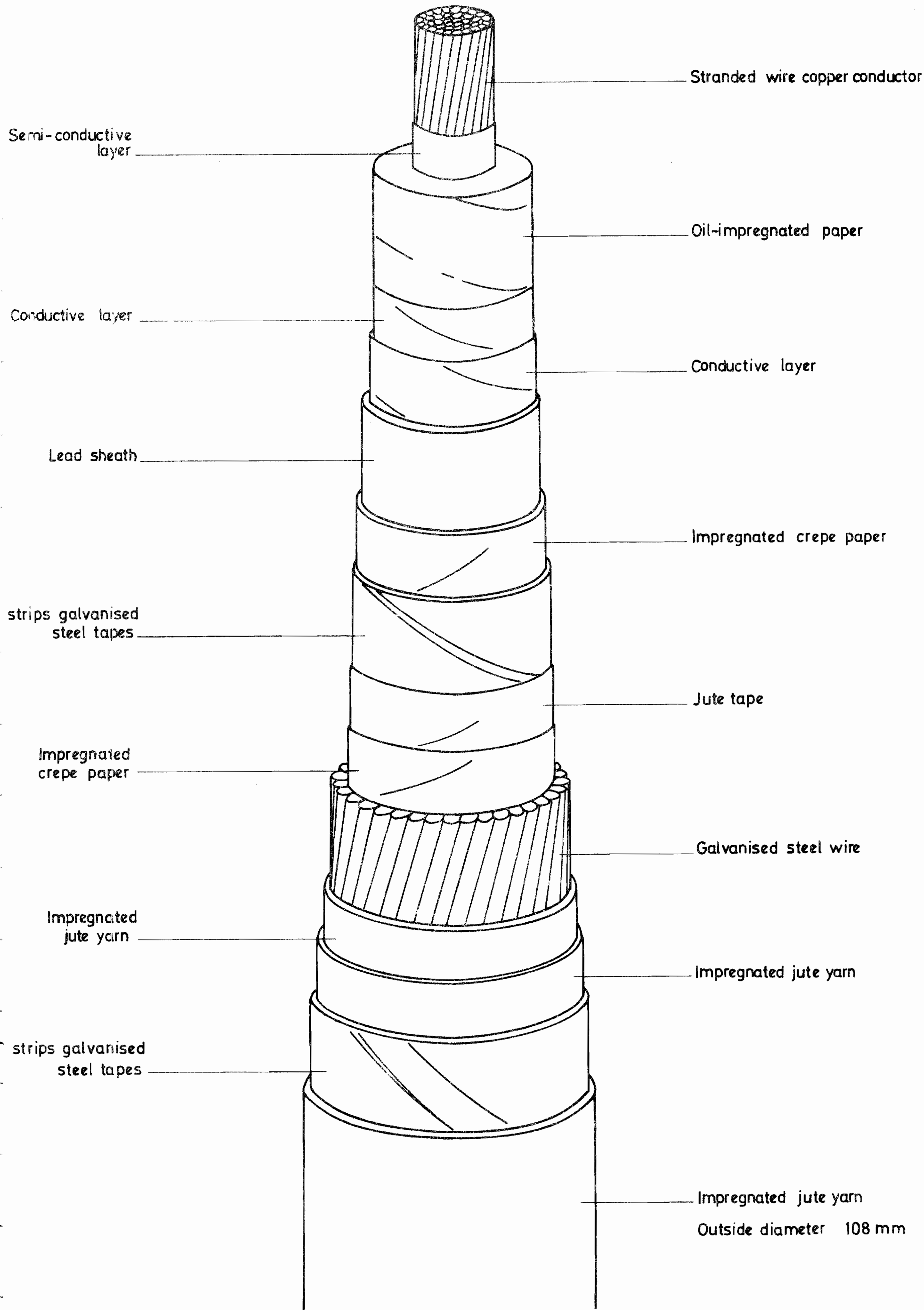


Figure 2.7

375 kV HVDC TOWERS FOR BOTH A MONOPOLAR AND A BIPOLAR OVERHEAD LINE COMPARED WITH A TOWER FOR AN AC 400 kV DOUBLE CIRCUIT LINE.

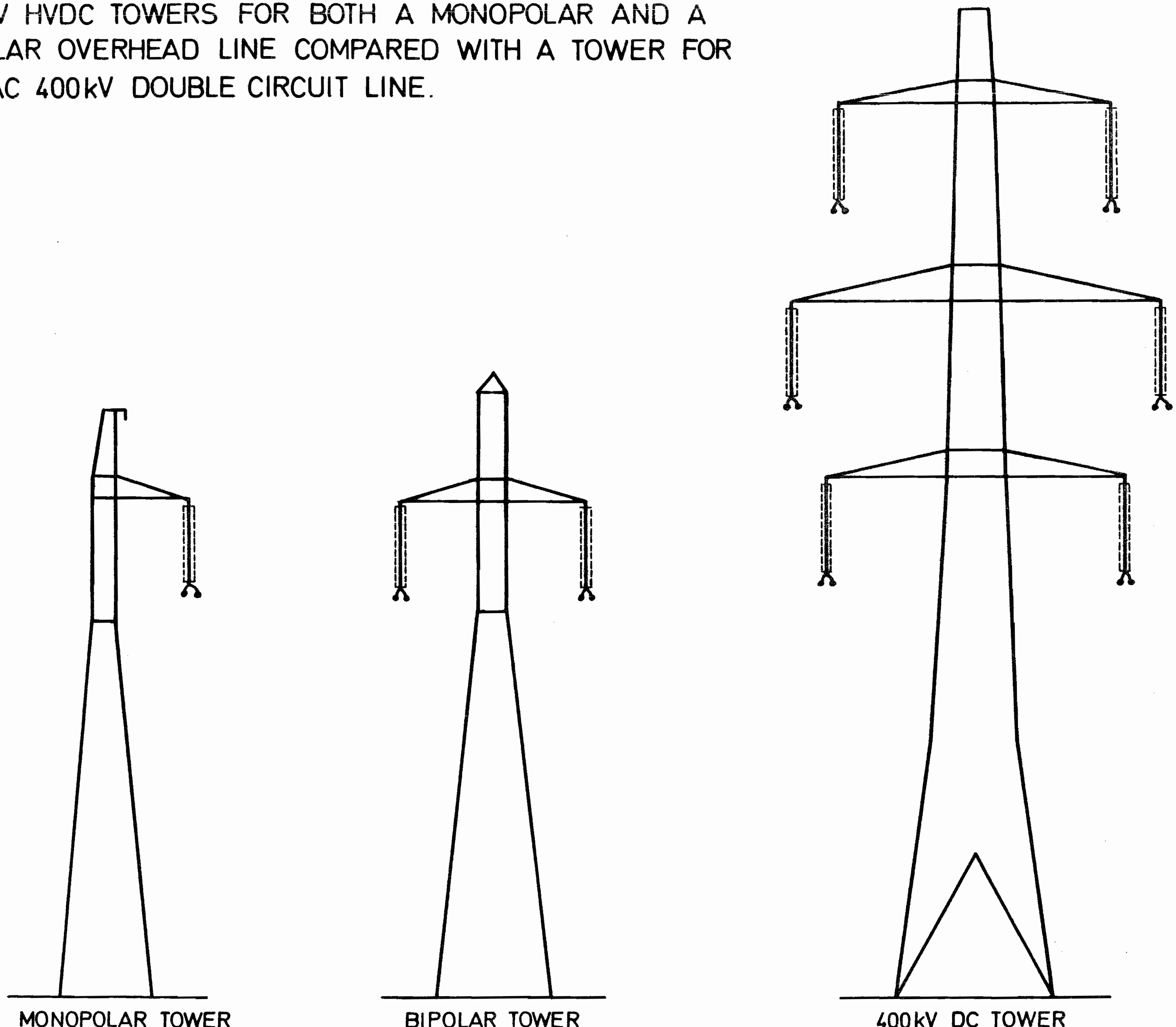


Figure 2.8

LOCATION OF HVDC SCHEMES (see Table 2.2)

3 OVERLAND BULK TRANSMISSION: AC VERSUS HVDC

3.1 Introduction

This section reviews the most economic means of transmitting 1, 000 MW over a distance of 400 km. It is well known that for bulk transmission of energy over a very long distance overland (1, 000 km or more), DC transmission can be more economic than AC. For shorter distances, it is necessary to examine the proposition in detail to determine where the cross-over point from AC to DC lies.

To ensure a realistic comparison between AC and DC transmission, it is important that both schemes start at a common point and finish at another common point. Also, as at this time the proposition is a hypothetical one, all assumptions made should be applicable to both schemes.

It is assumed that the generation of 1, 000 MW would be at a voltage between 13.5 kV - 14 kV and fed on to a busbar at this voltage. The common point for both schemes would be the transformer side of the LV breakers onto this busbar. In practice, for a particular scheme, the DC rectifier transformers or the AC transformers could be the generator transformers at the power station. Even in the late 1980's or early 1990's, 1, 000 MW would be a large proportion of the Icelandic load and as a 220 kV system is already being developed on the West side of Iceland, the common point at the receiving end is assumed to be on the transformer side of the 220 kV circuit breakers on to a 220 kV busbar at a substation near the load centres.

A substation at a lower voltage would not be able to cope with

such a large influx of power without further detailed study.
The other important assumption to be made before considering an AC scheme and then a comparable DC scheme is the level of security required. It is assumed that full supplies must be maintained for either a single circuit line fault or with a single circuit line out for maintenance.

3.2 Typical AC Scheme

3.2.1 Description

A schematic diagram of a suitable scheme is shown in Figure 3.1. To be able to transmit a 1,000 MW over a distance of 400 km, the voltage would have to be higher than 275 kV; 380 kV has been chosen.

Because of wind conditions and difficulty with foundations in Iceland, two separate single circuit lines with 2 x 400 mm^2 - zebra[1] conductors, 1,000 MVA normal rating would give the required level of security. An outline sketch of a typical 380 kV single circuit tower is shown in Figure 3.2(a).

At each end, the single circuit lines terminate at a 3-switch mesh transformer substation with 380 kV, 33 GVA circuit breakers. The two sending end generator transformers are rated at 13.8 kV/380 kV, 608 MVA capacity and at the receiving end the two auto transformers are 380 kV/220 kV, 608 MVA, capacity.

In practice, a scheme of 1,000 MW would probably be developed in stages. The two single circuit lines would be built at the beginning of the development, but the transformers would be smaller and would be added in stages to match the development of load and generation. At the receiving end, the size of the transformers would be say 200 - 300 MVA and therefore at least four would eventually be required in two banks of two.

---

(1) This is the trade name given to this design of conductor.

At the sending end, the generator-transformers are approximately 30 to 40% dearer than the equivalent size auto transformers. It would be probable that without any detailed knowledge of the time scale of the development and size of generator units only two transformers would be installed from the outset.

Depending on the development of the 220 kV system at the time this scheme is put into operation, it may be necessary to install some additional voltage support equipment such as shunt capacitors to maintain system volts under fault condition. It is assumed for this study that none will be required.

3.2.2 Capital Cost of the AC Scheme

Based on cost estimates obtained from various British and European manufacturing sources, the following cost estimates are derived (in U.S. $).

608 MVA, 13.8 kV/380 kV Generator Transformer	2.47 million
608 MVA, 220 kV/380 kV Auto Transformer	1.77 million
380 kV Switchgear Bay	0.55 million
380 kV, 2 x 400 mm^2 zebra conductors, single circuit overhead line	0.17 million/km

The cost estimates include civil works, protection, auxiliary equipment, erection and a 20% allowance for engineering and contingencies.

As shown in Figure 9, the following equipment listed in the table below is required for the AC scheme. The capital cost of this equipment is as follows:

Number Required	Equipment Description	Capital Cost $ Million
2	608 MVA, 13.8 kV/380 kV Generator Transformer	4.94
2	608 MVA, 220 kV/380 kV Auto Transformer	3.53
6	380 kV, Switchgear Bay	3.30
2	400 km of 380 kV, 2 x 400 mm^2 - zebra conductors, single circuit overhead line	135.20
	Total Capital Cost:	146.97

For the economic comparison between the AC and the DC scheme in Section 3.4, all the equipment required on the LV terminal side of the transformers, at both the sending and receiving substations, has been excluded as it is common to both schemes.

3.3 Typical HVDC Scheme

3.3.1 Description

A simplified schematic diagram of a HVDC scheme to transmit 1,000 MW is shown in Figure 3.3. The lay-out is for a 1,330 Amp bipole arrangement operating at 375 kV with the mid-point earthed.

At the rectifier station, banks of AC filters would be required to overcome the 5, 7, 11, 13 harmonics plus damped arm filters to overcome the higher harmonics. In an actual scheme, it may be possible to have a unit connected arrangement where each pole of the bipole is fed directly, via the rectifier transformer, by a generator unit of matching capacity to the output of the DC pole. If this was possible, there could be considerable savings on filtering equipment. In this scheme, it is assumed that the generation feeds directly on to the 13.8 kV busbar and this would be able to provide any reactive support required at this point. At the inverter station, a synchronous compensator or equivalent static device would be required. For no form of compensation to be required the short circuit level on the 220 kV busbar must be of the order of 5,000 MVA.

To give the required security, the overhead lines comprise monopolar 2 x 149 mm^2 plover[(1)] conductors. The lines are designed to carry 750 MW without exceeding 75^{o} F and it would be acceptable for short periods during fault or maintenance periods for one circuit to run hotter and carry the total 1,000 MW. Figure 3.2(b) shows an outline of a tower for a monopolar line. A 380 kV single circuit tower, which is required for the AC scheme, is shown for comparison in Figure 3.2(a).

---

(1) This is the trade name given to this design of conductor.

To obtain the 1,000 MWs on one circuit when a permanent line fault or maintenance occurs, the polarity of one of the poles has to be reversed and run in parallel with the other pole. Then 2,660 Amps at 375 kV flows on one monopolar line and returns via earth.

3.3.2 Capital Cost of HVDC Scheme

The Capital cost estimates for the converter stations were obtained from manufacturers on a turnkey basis. An overall price was obtained for the supply, erection and commissioning of all the equipment required rather than obtaining the price of each main item of plant separately. It was found that within limits, the cost of the converter stations is proportional to the MW transmitted rather than the transmission voltage.

At the rectifier station, the main items of equipment included in the price are the harmonic filters, rectifier transformers, thyristor valves in the three phase bipole bridge and the DC smoothing reactors. At the inverter station, the equipment is identical to the rectifier station except that the harmonic filters are replaced by a static or synchronous compensator and a separate price is given for it.

The table below summarises the capital cost of this particular scheme. All costs include a 20% engineering and contingency allowance. Without a detailed analysis of the future 220 kV system in Iceland, it is assumed that 300 MVA of synchronous compensation equipment will be required.

Equipment Description	Capital Cost $ Million
Rectifier and Inverter Stations ($\pm$ 375 kV, 1,000 MW)	105.36
Synchronous Compensation Equipment (300 MVA)	10.14
2 x 400 km of 375 kV, 2 x 149 mm^2 plover conductors, monopolar line ($ 91,800/km)	73.44
Total Capital:	188.94

3.4 Economic Comparison between AC and HVDC Schemes

3.4.1 Transmission Losses

As both schemes have the same generation source and transmit the same load, the only running cost that can be attributed to each scheme is the cost of the energy losses. It is assumed that the cost of the energy supplying the losses is 8 mills/kWh which is the estimated cost of energy from Sigalda.

(a) Annual Losses in the AC Scheme

With a load of 500 MW in each 3 phase circuit, the losses per circuit are 26.5 MW.

The transformer losses are assumed to be 0.5% of load. Therefore, at the sending end the transformer losses are 5 MW and at the receiving end the transformer losses are 4.7 MW.

As the load factor of the power source is 91%, the total annual energy losses are 62.7 x 8,760 x 0.91 = 500 GWh.

Annual Cost of losses (at 8 mills/kWh) = $ 4 Million

(b) Annual Losses in the HVDC Scheme

The line losses in each monopolar line are 17.2 MW.
In the converter stations, the losses are $1\frac{1}{2}$% of transmitted load.

At the rectifier station, the loss is 15 MW
At the inverter station, the loss is 14.5 MW.
The total energy losses are 63.9 x 8,760 x 0.91
= 509 GWh

Annual Cost of losses (at 8 mills/kWh) = $ 4.08 Million

3.4.2 Economic Comparison

If it is assumed that the commissioning date of the schemes is the first day of year 3, then the incidence of capital expenditure in percent is given below:

Year	1	2	3
Incidence of Expenditure (% of total)	40	55	5

The life of the transmission equipment is assumed to be 25 years and the annual operation and maintenance costs are assumed to be 1.0% of the capital cost.

The capital costs for the AC and the HVDC schemes are derived in Section 3.2.2 and 3.3.2 respectively and all the costs required for the economic comparison are summarised below:

AC Scheme

	$ Million
Capital Cost	146.97
Annual Operation and Maintenance Costs	0.73
Annual Cost of energy losses	4.0

HVDC Scheme

Capital Cost	188.94
Annual Operation and Maintenance Costs	0.94
Annual Cost of energy losses	4.08

Even though it can be seen by inspection that the HVDC scheme is more expensive than the AC scheme, the full analysis over the life of the plant is shown in Table 2. A 10% test discount rate has been used to present worth the annual differential costs to the commissioning date. Over the life of the plant, the extra net present value cost of installing an HVDC transmission scheme instead of an AC scheme would be \$ 48.46 million (See Table 3.1). This rules out DC transmission under the conditions here assumed.

TABLE 3.1

Determination of the Extra Cost of Installing an HVDC Scheme Instead of an AC Scheme

(All costs are in $ Millions)

Year	AC Scheme Costs				HVDC Scheme Costs				Differential cost of (HVDC) - (AC) i.e. col 8 - col 4	Differential cost col 9 discounted to first day of year 3
	Capital	Operation and Maintenance	Losses	Total	Capital	Operation and Maintenance	Losses	Total		
	1	2	3	4	5	6	7	8	9	10
1	58.79	-	-	58.79	75.58	-	-	75.58	16.79	19.39
2	80.83	-	-	80.83	103.92	-	-	103.92	23.09	24.24
3	7.35	0.73	4.0	12.08	9.45	0.94	4.08	14.47	2.39	2.28
$\sum_{4}^{27}$	0	$\sum_{4}^{27}$ 0.73	$\sum_{4}^{27}$ 4.0	$\sum_{4}^{27}$ 4.73	0	$\sum_{4}^{27}$ 0.94	$\sum_{4}^{27}$ 4.08	$\sum_{4}^{27}$ 5.02	$\sum_{4}^{27}$ 0.29	2.55
									Total extra NPV cost	48.46

Note: *It is assumed all costs are incurred at the middle of the year.

Figure 3.1

SCHEMATIC DIAGRAM OF AN AC TRANSMISSION SCHEME (380kV, 1000MW)

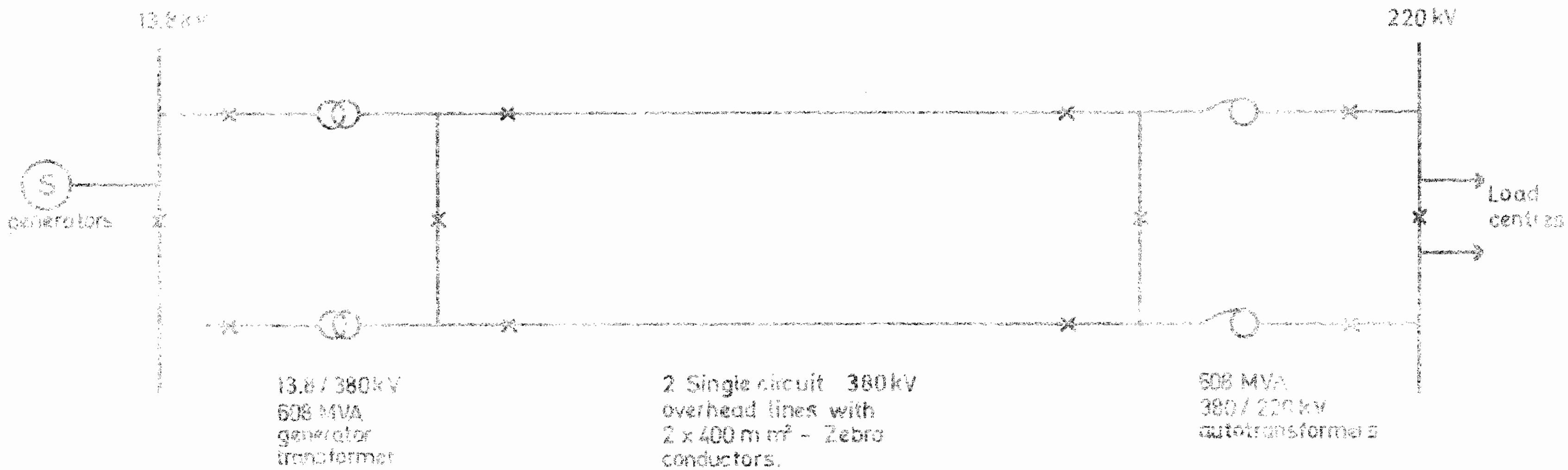
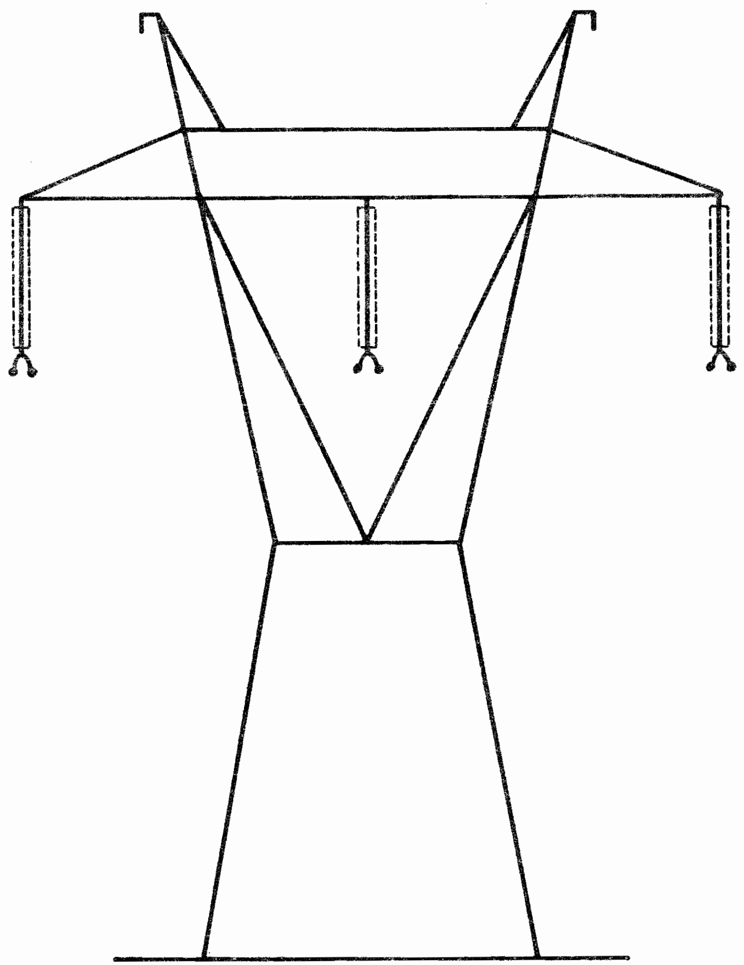


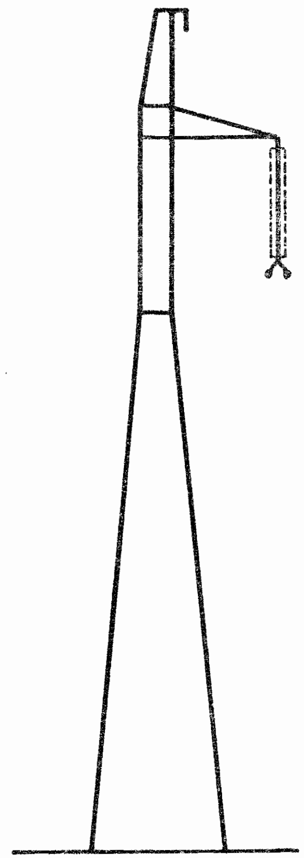
Figure 3.2

COMPARISON OF TOWERS FOR BOTH AC AND HVDC LINES OF EQUIVALENT CAPACITY

a) 380 kV AC single circuit tower



b) 375 kV DC monopolar tower



SCHEMATIC DIAGRAM OF AN HVDC TRANSMISSION SCHEME (1330 amps, ± 375 kV, 1000 MW)

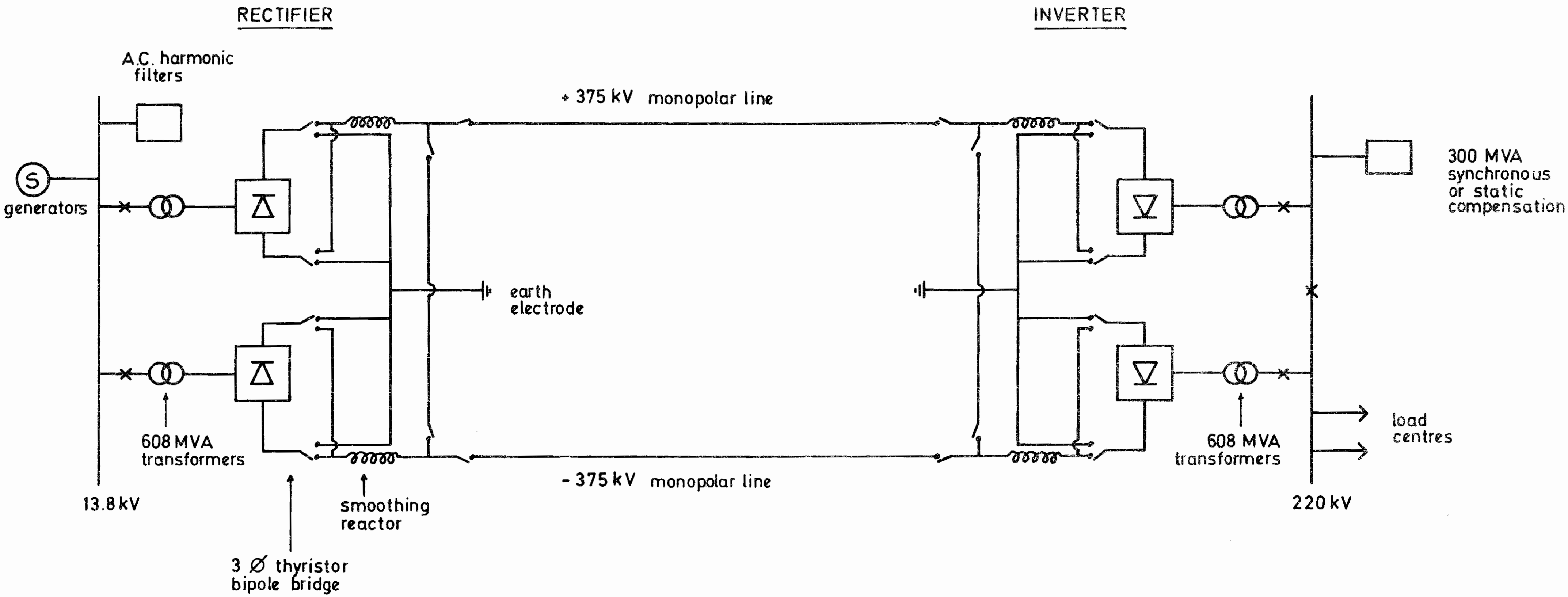


Figure 3.3

to transmit the power via overhead lines to a suitable point in the Scottish system. Without detailed study, this is assumed to be the Beauly 275 kV substation near Inverness, approximately 180 km from the Cape Wrath area.

The advantage of choosing this point is two-fold. Firstly, there is a large pumped storage installation at Foyers (300 MW) which feeds into this sub-station so that at night, during light loads, it could absorb a large proportion of the imported energy. If a fault on the cable occurred, pumped storage could quickly compensate the system for a loss of 630 MW by changing from the pumping mode to the generating mode. The second advantage is that near Beauly, at Invergordon (30 km away) is a large aluminium smelter with an electrical load of approximately 240 MW and this would help also to absorb the large import of power during light load conditions and reduce the flow of power further south.

For the economic study the capital cost estimates would start from the rectifier transformer terminal on the AC busbar side and the study would exclude all costs associated with the AC sub-station.

Similarly, at the inverter end the cost would finish at the AC terminal side of the inverter transformers.

The following sections look at the main factors which have to be taken into consideration when designing a suitable scheme.

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The following sections look at the main factors which have to be taken into consideration when designing a suitable scheme.

4.2 Geographical and Physical Constraints

4.2.1 Introduction

The physical aspects of the environment which have to be considered for a cable scheme are the depth of water the cable will be laid in; the type of surface on the sea-bed; the temperature of the water surrounding the cables; currents; and general sea conditions for laying or repairing the cables.

Account will also have to be taken of the physical state of a suitable landing site and chemical or biological conditions over the cable route.

These topics are discussed in more detail below.

4.2.2 Depth of Water and Sea-bed Contours

From Admiralty charts, the water is deeper between Scotland and Faroes than between Faroes and Iceland. Before deciding on the final cable route, it would be necessary to carry out a detailed survey of probable routes.

Examining Figure 4.1, which shows the sea-bed contours between Iceland and Faroes, it would appear possible to find a route which goes no deeper than 450 metres and a line is marked on the diagram indicating a possible route.

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Between Scotland and Faroes, the water is much deeper with the depths ranging up to 1,250 metres in the deep channel which runs in a north-easterly direction midway between the two countries. It may be possible, after a detailed survey to find a route which would keep to a depth of less than 1,000 metres without substantially increasing the route length. A possible route which has a high probability of keeping to a depth of less than 1,000 metres (550 fathoms) is also indicated (See Figure 4.2).

4.2.3 Sea-bed Conditions

There is a certain amount of information available on the sea-bed around the North Coast of Scotland and up towards the deep trough. The result of a survey carried out to determine the type of sea-floor by taking spot samples from the sea-bed are shown in Figure 4.3 for this area. The sand marked on the chart is shell-sand and very abrasive.

There have been some surveys carried out in the Faroes area but no details of the results are known at present. It is known that the sea-floor around the Faroe Islands is very rocky and very unsuitable for submarine cables but if it is necessary to land on the Faroes the best place would probably be on Sudero.

Between Faroes and Iceland, no details of the sea-bed are known.

4.2.4 Temperatures at the Sea-bed

The temperatures of the water surrounding the cable will influence the rating of the cable, the maximum temperature of the water is therefore important.

Figure 4.4 gives a certain amount of information on mean and maximum temperatures in the form of contours of monthly averages at various depths during the year.

Maximum surface temperatures occur normally in August and may reach 16° C. At 100 metres, there have been some observations of 13° C in the shallower areas where a reasonable amount of mixing would take place. Minimum sea surface temperatures in February expressed as a monthly mean are about 5 - 7° C. Thus, in some parts of the traverse, floor temperatures may be as high as 14 - 15° C but the maximum may be very much lower in other deeper parts.

From the maximum surface temperature contours, in August, the maximum surface temperatures occur near the Scottish coast and it is likely that the maximum sea-bed temperature would also occur in this area of shallow water. If the project is carried out, special measurements will have to be made to determine this temperature.

4.2.5 Weather and Tidal Currents

The weather in the area between Iceland-Faroes-Scotland can be very rough. From the experience of the British Post Office who are responsible for a communications cable between Scotland (Gairloch) and Faroes (Torshaven), it is found that the weather has never prevented a repair being carried out to the cable for longer than a week even though half of the faults occurred on the cable during the winter months. The majority of the faults were caused by trawling activities.

There are strong currents in the path of the cable route; details are not known at this stage. The design of the cable would have to take account of them as they could cause cable chafe.

4.2.6 Chemical and Biological Conditions

No investigations have been carried out at this stage to discover whether the cable may be affected by any chemical or biological conditions.

4.2.7 Landing Sites

Suitable sites would have to be chosen so that the cables are brought ashore in an area sheltered from the sea. Ideally, it should be possible to bring the cable laying ship reasonably close to the shore. It would be advantageous if the sea-bed had a sandy/mud bottom as in shallow water the cables would be buried to give them a certain amount of protection.

4.2.8 Summary of Physical Unknowns

From the above information in Figures 4.1 and 4.2 there is a reasonable chance of finding a suitable cable route. On the Scottish side of the deep trough the sea bottom along the cable route will be mainly a mixture of sand and gravel. Even though the sand is abrasive, it will do far less damage to the cable than rocks and the cable design can take account of it.

The weather should present no serious delays to carrying out repairs to the cable but when a long period of settled weather is required to lay the cable it could cause serious delays to an installation programme. This has been experienced in the development of the North Sea oil fields.

For the cable design it will be necessary to determine:

1. Maximum depth the cable will be laid in and a

profile of the sea-bed along the route.

2. The maximum temperature of the water surrounding the cable.

3. The maximum period the weather can be expected to remain settled for and then to determine whether it will be possible to lay the cable in one continuous length in this time period.

4. A detailed survey of the composition of the sea floor.

5. The strength of the currents along the cable routes.

These are the main physical unknowns which need to be determined.

4.3 Power Transmission

4.3.1 Parameters for Selecting a Suitable Cable

The distance between Iceland and Faroes is 482 km and between Faroes and Scotland 425 km. It would be possible to obtain a ship large enough to carry a cable, made in one continuous length, to stretch from Iceland to Scotland. It would be necessary therefore to have two half-lengths and land the ends on Sudero Island to joint the two halves together as it is not desirable to carry out jointing operations on board ship.

The other major factor to be taken into consideration is the water pressure on the cable due to the extreme depths between Scotland and Faroes. Until now, the maximum depth proposed for a submarine cable is 550 metres in the crossing of the Skagerrak Sea.

Due to the length of cable and depth of laying the choice lies between a solid cable or a gas-filled cable; an oil-filled cable is precluded by the long length. Even with a gas-filled cable, it would be necessary to carry out extensive tests to make sure it was possible to maintain the gas pressure over this length. It should also be remembered that even though the direct route between Iceland-Faroes and Faroes-Scotland is 482 km and 425 km respectively, the actual cable route will probably be 5 to 10% longer to take account of detours required to avoid excessive depths or underwater precipices.

A decisive choice between a gas-filled cable or a solid type cable could only be made after very extensive study and research which is outside the scope of this pre-feasibility report.

4.3.2 Design and Operating Parameters

The design parameters can be classified under two separate groups: mechanical and electrical.

(i) Mechanical design has to be given protection against:-

(a) Abrasion arising from cable movement. The tendency of a cable to move on the sea-bed depends on the traverse component of the water current relative to the square root of the immersed weight/diameter ratio of the cable.

(b) Bending damage of over sea-bed rocks.

(c) Water pressure.

(d) Chemical and marine life.

(e) Strength to support cable weight during the laying or recovery process without damage to the cable. Depending on the type of cable, it could weigh between 30 to 50 kg/metre in air.

The maximum depth in which a cable can be laid is subjected to some conjecture and expert opinion ranges between 550 metres (as in the Skagerrak project) to an absolute maximum of 1,000 metres. Extensive studies would be required to prove what the maximum depth is, even though some people think it may be technically possible to design a cable for a depth of 1,000 metres.

(ii) Electrical design parameters

The cross-sectional area of the copper conductor must be such that there is no excessive voltage drop down the cable which in turn keeps the copper losses and the heat dissipated to an acceptable figure. The cable dielectric must be able to withstand the electrical stresses set up under steady state and transient conditions.

CIGRE Study Committee No. 27 has laid down recommendations for tests on DC cables for a rated voltage up to 550 kV and also for mechanical tests on submarine cables.

(iii) Operating parameters

Practical experience of HVDC submarine cables at present is up to an operating voltage of $\pm$ 250 kV for either gas-filled or solid cables. Using a 1,000 mm^2 copper conductor cable, a rating of up to 1,330 Amps may be possible. Opinions vary on the exact rating in the range of 1,000 to 1,330 Amps. One manufacturer thought it was possible to design a suitable cable to operate at $\pm$ 300 kV 1,100 Amps.

At normal operating temperatures, the DC resistance would be somewhere between 0.0204 and 0.022 ohms/km and the voltage drop down the cable between Iceland-Faroes-Scotland would be of the order 5 - 8% of normal operating voltage. This is quite a usual figure for long transmission lines, but for AC cables of this length the voltage drop would be so large that it would be impossible to transmit the power down them.

4.3.3 Number of Cables Required to Transmit 2,000 MW

If a suitable cable could operate at $\pm$ 250 kV, 1,330 Amps or $\pm$ 300 kV, 1,100 Amps, then only six cable circuits would be required to transmit 2,000 MW. The 330 MW rating of each cable is both the normal and the maximum rating. If a fault developed on one cable the total power transfer would have to be reduced by the amount of the load on the faulted cable. The lost load could not be redistributed amongst the five remaining cables as the cable ratings would be exceeded.

On economic grounds the laying of a spare cable cannot be justified as the outlay of an extra $ 185.7 million would only increase the availability of the overall scheme by approximately 1.5%; see Section 4.3.5. If a seventh cable was laid regardless of costs it could be used to provide a disconnectable supply to the Faroes but in comparison with the costs of internal generation the cost of the converter equipment, for a small supply, plus a proportion of the cable cost would make it uneconomic. As the straight line route is 907 km, it is realistic to assume the actual length of each cable to be 1,000 km. As each cable would be made in two sections and jointed on the Faroes, each section would weigh somewhere between 16 - 23 x 10^6 kg (16,000 - 23,000 tons), depending on the design of the cable.

4.3.4 Electrical Losses in the Cables

To reduce the losses in the cables, it is preferable for the cables to be designed to operate at 300 kV rather than 250 kV even though all practical experience to date has been at 250 kV. For this study, it is assumed that the cables will operate at $\pm$ 250 kV, 1,330 Amps and that the resistance of the cable is 0.02 ohms/km.

The total length of each cable is assumed to be 1,000 km. Therefore, the total losses in each cable between Iceland-Faroes-Scotland would be 34 MW and the total losses in the 6 cables would be 204 MW under normal operating conditions. This is 10% of the transmitted power.

4.3.5 Availability of Cables

The Experience of the British Post Office with faults on the Scotland (Gairloch)-Faroes (Torshaven) cable can give an indication of the frequency and type of faults that might occur on a power cable. The cable was laid in 1961 and there have been 17 faults on the cable of which 14 faults were due to trawler damage. It is interesting to note that the trawler damage occurred in two distinct areas. Five faults occurred 55 km to 160 km from Torshaven and nine occurred 314 km to 335 km from Torshaven. In 1970, the section of cable where nine faults had previously occurred (314 - 335 km) was reinforced with triple armour and since then no further faults had occurred in this section.

The other three faults were due to cable chafe and all occurred within 15 km of Torshaven. It is known that the sea-bed around the Faroes is very rocky and with the strong currents, movement of the cable has occurred and produced cable chafe.

On the basis of Post Office experience, it should be possible to design the cable to eliminate the majority of these faults. Near the Faroes where there are rocks, the cable can be specially strengthened to stop any uncontrolled bending. Extra armouring can be included where damage from trawlers is likely to occur.

If these measures are built into the design, the cables should have a very high availability. To confirm this statement, another Post Office cable was laid between Orkney-Shetland and Shetland-Faroes (Torshaven) in 1972 and there have been no faults to date.

If a fault did occur on one of the six HVDC cables, the transmitted power would only be reduced by 17% for the period of the fault. If a fault took a month to repair and only one fault occurred per year, the average annual availability of the overall scheme would only be reduced to 98.5%. This is the main reason why a seventh cable cannot be justified for a spare as it would only improve the overall operating availability by $1\frac{1}{2}$%.

4.3.6 Overhead Lines

At the landing point on the Scottish shore, the cables would terminate in outdoor sealing ends mounted on steel or reinforced concrete structures. All the + 250 kV cables would be connected in parallel to a positive busbar and similarly all the - 250 kV cables to a negative busbar. Conventional line droppers from two monopolar lines to the positive and negative busbars would connect the cables to the overhead lines.

Two monopolar lines with 4 x 400 mm^2 zebra conductors would be required to transmit the power to the inverter station at Beauly. Each line would be approximately 180 km long and one line would operate at + 250 kV, 4,000 Amps and the other at - 250 kV, 4,000 Amps. If there was a fault on one line the other line would be capable of carrying the full load.

The design of the monopolar towers would be similar to the one illustrated in Figure 3.2(b) except that the overall height would be reduced by approximately 3 metres as it would be operating at a lower voltage.

At full load the line losses on each monopolar line are 27.9 MW. From Section 4.3.4 the total cable losses are 204 MW at full load, therefore the total transmission losses, excluding the converter losses are 259.8 MWs.

4.4 HVDC Conversion

The maximum voltage rating which the cables can be designed for will determine the overall operating voltage of the scheme. In the previous section it was decided that this would be 250kV and that 6 cables would be required to transmit 2,000 MW if each cable operates at either ± 250 kV, 1,330 Amps. Therefore, at the converter station at each end there would be 3 x 660 MW bipoles with the mid points earthed. A simple schematic diagram of the overall scheme is shown in Figure 4.5.

It is assumed that the power source is provided from a number of hydro stations and the power is supplied to the AC busbar at the rectifier station, in Iceland, at 220 kV. Each pole of the three bipoles are connected individually to the 220 kV busbar via a 400 MVA, 220 kV/250 kV rectifier transformer and a 220 kV circuit breaker. The DC outputs from the bipoles are fed through smoothing reactors to the sealing ends of the DC cables.

Connected to the AC busbar at the rectifier station, four banks of filters are required to remove the 5, 7, 11, 13 harmonics. Damped arm filters are also needed; see Section 2.1. If each pole of the bipoles are supplied by separate unit generators and not connected to each other or to a larger network, then the AC filters would only need to remove the 5th and 7th harmonics with consequent financial savings. If it is required to incorporate the separated unit generators into a larger interconnected system at a later date, then extra filters could be added at that time.

The inverter station, at the receiving end in Scotland, is basically identical to the rectifier station except that there are only two incoming single circuit overhead lines instead of six outgoing cables and that the AC filtering equipment is replaced by synchronous compensation equipment.

For no synchronous compensation equipment to be required it would be necessary to have a short circuit level of around 5,000 MVA minimum on the 275 kV AC busbar. It is probable that at Beauly, the level would be very much less and some form of synchronous compensation or static compensation would be needed. A 600 MVA static compensator comprising saturated reactors shunt capacitors and step down transformers would be required if the short circuit level was at 2,500 MVA.

4.5 Cost of HVDC Scheme

The description of the equipment required for this scheme is given in the previous Section 4.4. Table 4.1(a) summarises the equipment required and the associated capital costs. In Table 4.1(b) the operating and maintenance costs are shown.

In the following subsections the derivation of these cost estimates are discussed in greater detail. All the cost estimates refer to the base date of the 15th January, 1975. The exchange rates used in the preparation of the cost estimates are given in Section 1, Table 1.1.

4.5.1 Submarine Cables

From Section 4.3.3 six cables will be required to operate at $\pm$ 250 kV, 1,330 Amps. It is assumed that the length of each cable will be 1,000 km to allow for route deviations.

Estimates obtained from different manufacturers for the cost of cables are reasonably consistent and all lie within the range \$ 122 per metre to \$ 130 per metre. The biggest variation occurs in the estimates for laying the cable, due to there being so many unknowns. Estimates vary between 20% of the capital cost of the cable for a solid type cable and 90% for a gas-filled cable.

It is assumed here that the cable used is of the solid type and the capital cost including laying is \$ 154.72 per metre. This is the average of the cost estimates obtained from manufacturers of solid type cables. The total capital cost of six cables would be \$ 928.32 million to which a 20% contingency allowance should be added giving a final cost of \$ 1,114 million.

4.5.2 Overhead Lines

Two monopolar lines with 4 x 400 mm^2 conductors, 180 km long, will be required to transmit the power from the landing point on the Scottish coast to Beauly (see Section 4.3.6). The capital cost of each line is taken to be $ 153,000/km.

The total capital cost of the two monopolar lines is then $ 55.1 million. With 20% added for engineering and contingencies, the final cost is $ 66.1 million.

4.5.3 Converter Stations

The capital cost estimates for the converter stations, each rated at 2,000 MW, were obtained from manufacturers on an overall turnkey basis. Taking the average of the cost estimates provided by different manufacturers, the capital cost of the rectifier and the inverter stations comes to $ 146.3 million. This cost covers the supply, erection and commissioning of all the equipment from the rectifier side of the AC switchgear to the sealing ends of the DC cables, and the AC harmonic filters. At the inverter station, it includes all the equipment from the downdroppers from the monopolar lines to the AC switchgear side of the inverter transformer. An allowance has been made in the price for civil works and telecommunication equipment but not for synchronous compensation equipment at the inverter station. The cost of the synchronous compensation equipment would be an extra $ 14.1 million, making a total cost of $ 160.4 million. A further 20% should be added to this cost to cover engineering and contingencies which would give a final cost of $ 192.5 million.

4.6 Cost of Nuclear Station in Great Britain

In Great Britain, the type of nuclear reactor being installed in the late 1980's or early 1990's would be either the Steam Generator Heavy Water Reactor (SGHWR) or the High Temperature Reactor (HTR).

At present, six 630 MW SGHWR units (660 MW installed rating) have been ordered for two stations and installation is planned for the early 1980's. Estimates of the capital cost of the two stations have been published and these form the basis of the "optimistic estimates" given in Table 4.2.

From past experience when building a new design of reactor the actual cost is often very much in excess of the original estimate due to the occurrence of many unforseen problems. In the economic assessment, in Section 4.7, it is considered prudent that not only an optimistic set of cost estimates should be examined but also a pessimistic set, which allows for some escalation of costs. This will give some indication of the sensitivity of the results to certain basic cost assumptions.

The pessimistic set of estimates is based on international experience of the cost of light water reactors with a substantial element included to cover an increase in real costs, i.e. excluding cost increase due to inflation. The large capital cost difference between the two estimates is partly compensated for by a difference in construction times.

In the pessimistic case, it is assumed that it only takes four years to build the station but in the optimistic case a construction period of five and a half years is assumed.

The annual operation and maintenance costs in the pessimistic case are assumed to be 4% of the capital expenditure, whereas the optimistic case is based on costs of similar conventional sized stations with an allowance for the fact that it is a nuclear station.

Fuel costs for both sets of estimates are based on international experience. In the pessimistic estimate, an element is included to cover an increase in real costs of the fuel.

4.7 Economic Assessment

The objective of this section is to determine the cost at which the power must be supplied to the rectifier station in Iceland. For the HVDC submarine cable scheme to be economically feasible, the cost of energy delivered from the inverter station at Beauly to the Scottish system must be less than the cost of nuclear energy generated in Scotland.

The analysis is carried out for two nuclear energy costs. Case "A" is for the pessimistic set of nuclear cost estimates and Case "B" is for the optimistic set of nuclear cost estimates (see Section 4.6 and Table 4.2). Throughout the rest of this section, they are referred to as Case "A" and Case "B" respectively.

4.7.1 Cost of HVDC Energy Delivered to Scotland

It is assumed that if contracts are awarded at the beginning of year 1, commissioning would commence at the start of year 5. The assumed commissioning programme is laid down in Table 4.3.

Based on this commissioning programme and an availability of 95% for the hydro stations supplying the 2,000 MW, Table 4.4 shows the build up of power and energy at the receiving end at Beauly after taking into account the losses in conversion and transmission. These losses amount to 16% of the energy supplied to the rectifier station in Iceland.

The assumed incidence of expenditure for the main items of plant required for the HVDC scheme is given in Table 4.5. The incidence of expenditure for the cables is longer than is normal for transmission equipment because a large amount of development work will be required on the cable design, manufacture and laying techniques in very deep water.

Table 4.6 shows the incidence of capital expenditure for the various items of plant over successive six monthly periods.

The annual cash flows discounted to the commissioning date of the first cable are shown in Table 4.7. The energy delivered to the rectifier station in Iceland is also shown discounted to the same date with the 10% discount rate.

4.7.2 Cost of Nuclear Energy Displaced by HVDC Energy

After a large generating unit has been commissioned, it takes several years for it to reach its normal operating load factor. For this assessment it is assumed that the annual build up of availability for a 630 MWso nuclear unit is shown below:

Year	1	2	3	4	5
Average Annual Load Factor	25%	40%	50%	50%	65%

In the first line of Table 4.8, the energy that could be supplied by the HVDC scheme in each half year is shown. (This is taken from Table 4.4). It is assumed that nuclear 630 MW units will be installed in such a pattern that the total energy output from all the new nuclear units is always equal to or greater than the energy that the HVDC scheme could supply. To fulfil this condition, six nuclear units are required. Their installation pattern and energy build-up is shown in the middle section of Table 4. 8.

If the HVDC scheme is installed, it is assumed that the energy supplied from it would displace only nuclear energy. The proportion of the nuclear energy, from the six units, displaced by HVDC energy is shown in the bottom section of Table 4. 8. The nuclear cost that could be displaced by the HVDC scheme is the appropriate proportion (given in line 9) of the total cost of providing the nuclear energy (given in line 8).

It is reasonable to argue, that in practice, if the HVDC scheme was planned to be installed, the shortfall in energy, (i. e. the difference between what the HVDC scheme could supply and the total nuclear energy supplied), would be made up by running more expensive plant already in the system and not installing further nuclear units. This assumption would necessitate to stimulate accurately the operation of the Scottish system year by year. This is not practical for this pre-feasibility study and the assumptions made in the previous paragraph are therefore considered reasonable for the present purpose.

The incidence of capital expenditure for the nuclear units in both Case "A" and Case "B" is given in Table 4. 9 in percentage terms. Tables 4. 10 and 4. 11 shows the incidence of capital expenditure in monetary terms for both Case "A" and Case "B" respectively. The construction time for Case "B" is 18 months longer than for Case "A" and for the HVDC schemes. To enable the commissioning date of the nuclear units to be the same as in Case "A", the contracts would have to be awarded eighteen months earlier. This extra time period is indicated by a negative sign in the tables that refer to Case "B", i.e. Tables 4.11, 4.13 and 4.15.

The annual cash flows (i.e. capital, operation, maintenance and fuel costs) are given in Tables 4.12 and 4.13 for the two respective cases. Using a 10% annual discount rate, the net present values of the annual cash flows are derived and then summated. The base date for the discounting is the 1st day of year 5. The present value is then converted into an annuity extending over a 25-year period.

Table 4.14 and 4.15 shows the annual annuitised total nuclear energy costs and the proportion of these costs that can be displaced by the HVDC scheme for the two respective cases. These annual "displaced" costs are then discounted at 10% per annum to the base date and summated.

4.7.3 Cost of Energy Delivered to the HVDC Scheme in Iceland

In Sections 4.7.2 and 4.7.3, all the information required to calculate the cost at which the energy must be supplied to the rectifier station in Iceland has been derived. The calculation of the cost of the energy source is shown below for the two cases.

Let	(1)	Cost of energy source in mills/kWh	=	X
	(2)	Net Present Value cost of nuclear energy displaced in $ Million	=	Y
	(3)	Net Present Value cost of HVDC scheme in $ Million	=	H
	(4)	Net Present Value energy supplied by source in GWh	=	E

Then

$$X < \frac{(Y - H)}{E} \times 10^3$$

From Table 4.7

H = $ 1,457.24 million

E = 133,219 GWh

(1) For Case "A"

From Table 4.14

Y = $ 3,714.28 million

$$X < \frac{(3714.28 - 1457.24) \times 10^3}{133219}$$

$$< 16.94 \text{ mills/kWh}$$

(11) For Case "B"

From Table 4.15

$$Y = \$ \, 2,415.69 \text{ million}$$

$$X < \frac{(2415.69 - 1457.28)}{133219}$$

$$< 7.19 \text{ mills/kWh}$$

For Case "A" the cost of energy in Iceland has to be supplied to the converter station at a cost less than $ 16.9 mills/kWh for the scheme to be economically feasible. For Case "B" the cost of energy has to be less than $ 7.19 mills/kWh.

4.8 Discussion

4.8.1 Technical

According to Section 4.2, the unknown which will have to be determined is the maximum depth the cables would have to be laid to cross the deep trough between Faroes and Scotland. This is the most decisive technical factor in the whole project. Once this factor is known, the next question is whether a cable of the required rating can be designed to withstand the pressures created by the maximum depth and the mechanical forces exerted on it during the laying operation. It is essential that the required rating for the cable can be achieved as otherwise a lower rating would mean that the number of cables required would have to be increased. This would ruin any chance of the scheme being economically feasible. All the other unknowns, such as the maximum temperature of the water or details of the sea bottom along the whole of the route are required for the cable design but are only of secondary importance for the scheme.

The mechanical design of the cable, its manufacture and the question of physically handling the large quantities of both raw materials and finished cable will require much development work, whereas the electrical design is fairly well explored.

4.8.2 Economics

It is thought that the Icelandic energy can be supplied at a cost between 7 - 10 mills/kWh. If it is possible to supply it at 7 mills/kWh, then according to Section 4.7.3, the scheme would be economically feasible as it would be cheaper than Case "B" (the optimistic nuclear costs case), without even considering the intangible benefits which it is not possible to cost at this stage. From the British viewpoint, an example of an intangible benefit is that one less site is required for a large nuclear power station. In a heavily populated country each new site creates many environmental objections.

If the cost of Icelandic energy is at the top of the above range (i.e. at 10 mills/kWh), then the scheme would be feasible compared with the pessimistic nuclear cost estimates (i.e. less than \$ 16.94 mills/kWh) but not compared with the optimistic set of cost estimates (i.e. less than \$ 7.19 mills/kWh). The actual cost of the next generation of nuclear stations will lie somewhere between the two figures but at this point in time the cost estimates of the optimistic case would be more acceptable to the Electricity Authorities than those of the pessimistic case.

Now that capital has become very expensive, the construction period can have a very dramatic effect on the overall cost of a project. For a four year construction period and the incidence of expenditure assumed for the nuclear station in Case "A", the interest during construction (I.D.C.) amounts to 15% of the capital cost. This is based on a 10% discount rate. If the construction period lengthens to $5\frac{1}{2}$ years with the incidence of expenditure assumed for the nuclear station in Case "B", I.D.C. amounts to 31% of the capital cost.

In future, there will be great pressure to achieve shorter construction periods but from recent experience with nuclear stations, the period is longer than that assumed in both cases. If the period is longer, it would make the HVDC scheme more competitive.

Depending on how such a large capital project would be financed and the large number of unknowns and risks involved, it is questionable whether a higher discount rate than 10% should be used.

4.8.3 Future Work Proposed

The next stage in this project is to determine the cost of generating the required amount of power in Iceland. If it is found possible to provide the energy in the region of 7 mills/kWh, then more detailed economic studies should be carried out in collaboration with the Scottish Electricity Boards to enable accurate simulation of the operation of their systems to be allowed for, and also to determine the cost at which they would be interested in buying the energy.
If the results of these studies demonstrated that HVDC transmission is still feasible, a survey should be carried out to see whether it is possible to find a route across the deep trough between Faroes and Scotland at a depth of less than 1,000 metres and ideally less than 750 metres. This is the crucial question. If the depth of the best route did exceed 1,000 metres, the project would not be feasible until there were new discoveries in cable technology.

TABLE 4.1

Cost of HVDC Scheme

Number Required	Equipment Description	Total Capital Cost $ Millions
6	1,000 km Submarine Cable, 250 kV, 1,330 amps	1,114.0
2	180 km, 4 x 400 mm - Zebra conductors single circuit monopolar overhead line	66.1
2	Converter Station ±250 kV 3 x 660 MW bipoles with mid point earthed	175.6
1	Synchronous Compensation equipment 600 MVA	16.9
		1,372.6

Note: the capital costs include 20% engineering contingency allowance.

(B) Operating Costs
Annual Operation and Maintenance costs are 1% of capital ($1,372.6 million) i.e. £13.72 million.

TABLE 4.2

Nuclear Costs of 2 x 630 MW SGHWR Stations

Type of Estimate		Capital Cost in \$/kW	Operation and Maintenance costs in \$/kW	Fuel Cost in Mills/kWh
Pessimistic	Case A	780	31.2	3
Optimistic	Case B	572	10.4	2.5

Notes: (1) The capital cost excludes interest during construction but includes the cost of the initial fuel charge.

TABLE 4.3

Planned HVDC Commissioning Programme

Year	5		6		7	
Commissioning Date	1st January	1st July	1st January	1st July	1st January	1st July
Cables No.	1	2	3	4	5	6
Overhead lines	1 at +250 kV	1 at -250 kV	-	-	-	-
Bipoles at converter stations to match cable programme number and voltage	1 pole at +250 kV	1 pole at -250 kV	2 pole at +250 kV	2 pole at -250 kV	3 pole at +250 kV	3 pole at -250 kV
Synchronous Compensation	1	-	-	-	-	-

Note: The above programme assumes development contracts are awarded 1st January in year 1.

TABLE 4.4

Build-Up of MW GWh at Receiving AC Busbar in Scotland

Year	5		6		7		8	
6 month period starting	1st January	1st July	1st January	1st July	1st January	1st July	1st January	1st July
MWso from Iceland AC Busbar	333	667	1,000	1,333	1,667	2,000	2,000	2,000
GWh sent out from Iceland AC Busbar 95% availability	1,386	2,775	4,161	5,547	6,936	8,322	8,322	8,322
Losses at Rectifier Station ($1\frac{1}{2}\%$) in MW	5	10	15	20	25	30	30	30
Losses in cables in MW	34	68	102	136	170	204	204	204
Losses in lines in MW	3.1	6.1	16.2	24.7	40.3	55.8	55.8	55.8
MW received at Inverter Station	290.9	582.9	866.8	1,152.3	1,431.7	1,710.2	1,710.2	1,710.2
Inverter losses ($1\frac{1}{2}\%$) in MW	4.4	8.7	13.0	17.3	21.5	25.7	25.7	25.7
MW received at Beauly	286.5	574.2	853.8	1,135.0	1,410.2	1,684.5	1,684.5	1,684.5
GWh supplied during half-year to Scottish system	1,192	2,389	3,553	4,723	5,868	7,009	7,009	7,009

Note: The above is based on HVDC Commissioning Programme in Table 4.3

TABLE 4.5

<u>HVDC - Incidence of Capital Expenditure as a Percentage of Total Capital Cost</u>

Year	1	2	3	4	5
O.H. lines	-	-	40	55	5
Submarine Cables	10	20	30	35	5
Converter Station	-	-	40	55	5
Synchronous Compensator	-	-	40	55	5

Note: Commissioning is assumed to be at the beginning of year 5

TABLE 4.6

HVDC Incidence of Capital Expenditure in $ Millions

Six Months Up To End of Year	Cables						OH Lines		Converter Stations Pole No.						Sym. Comp.	Total
	1	2	3	4	5	6	1	2	1	2	3	4	5	6		
0.5	9.28															9.28
1.0	9.28	9.28														18.56
1.5	18.56	9.28	9.28													37.12
2.0	18.56	18.56	9.28	9.28												55.68
2.5	27.85	18.56	18.56	9.28	9.28											83.53
3.0	27.85	27.85	18.56	18.56	9.28	9.28										111.38
3.5	31.56	27.85	27.85	18.56	18.56	9.28	6.6		5.85						3.38	149.49
4.0	33.42	31.56	27.85	27.85	18.56	18.56	6.6	6.6	5.86	5.85					3.38	186.09
4.5	5.57	33.42	31.56	27.85	27.85	18.56	9.1	6.6	8.05	5.86	5.85				4.65	184.92
5.0	3.73	5.57	33.42	31.56	27.85	27.85	9.1	9.1	8.05	8.05	5.86	5.85			4.65	180.64
5.5		3.73	5.57	33.42	31.56	27.85	0.83	9.1	0.73	8.05	8.05	5.85	5.85		0.42	141.02
6.0			3.72	5.57	33.42	31.56	0.82	0.83	0.73	0.73	8.05	8.05	5.86	5.85	0.42	105.62
6.5				3.73	5.57	33.42		0.82		0.73	0.73	8.05	8.05	5.86		66.95
7.0					3.72	5.57					0.73	0.73	8.05	8.05		26.86
7.5						3.73						0.73	0.73	8.05		13.24
8.0													0.73	0.73		1.46
8.5														0.73		0.73
9.0																0
															TOTAL	1,372.6

TABLE 4.7

NPV of HVDC Capital, O and M and Energy

Six Months Up To End of Year	Incidence of of HVDC Expenditure	O and M Cost $ Millions	Incidence of Expenditure Capital and O and M $ Millions	Discounted Expenditure $ Millions	Energy delivered to rectifier station	Energy NPV in GWh
0.5	9.28	-	9.28	12.97	-	-
1.0	18.56	-	18.56	24.70	-	-
1.5	37.12	-	37.12	47.18	-	-
2.0	55.68	-	55.68	67.37	-	-
2.5	83.53	-	83.53	94.48	-	-
3.0	111.38	-	111.38	122.52	-	-
3.5	149.49	-	149.49	156.96	-	-
4.0	186.09	-	186.09	186.09	-	-
4.5	184.92	1.32	186.24	177.77	1,386	1,323
5.0	180.64	2.56	183.2	166.55	2,775	2,523
5.5	141.02	3.64	144.66	125.54	4,161	3,611
6.0	105.62	4.71	110.33	91.19	5,547	4,585
6.5	66.96	5.79	72.75	57.39	6,936	5,472
7.0	26.86	6.86	33.72	25.33	8,322	6,252
7.5	13.24	6.86	20.1	14.42	8,322	5,969
8.0	1.46	6.86	8.32	5.68	8,322	5,684
8.5	0.73	6.86	7.59	4.95	8,322	5,426
$\sum_{9}^{29}$	0	$\sum_{9}^{29}$ 13.72	$\sum_{9}^{29}$ 13.72	76.15	$\sum_{9}^{29}$ 16,644	92,374
			TOTAL	1,457.24		133,219

TABLE 4.8

Build-Up of Energy Supplied Via HVDC Cables

	Year	5	6	7	8	9	10	11 to 29
(1)	Half yearly HVDC GWh	1,192 2,389	3,553 4,723	5,868 7,009	7,009 7,009	7,009 7,009	7,009 7,009	7,009 7,009

Build-Up of Nuclear Energy GWh

	Nuclear Units	5	6	7	8	9	10	11 to 29
(2)	No. 1	693 693	1,102 1,102	1,379 1,379	1,379 1,379	1,795 1,795	1,795 1,795	1,795 1,795
(3)	2	693 693	1,102 1,102	1,379 1,379	1,379 1,379	1,795 1,795	1,795 1,795	1,795 1,795
(4)	3	693	693 1,102	1,102 1,379	1,379 1,379	1,379 1,795	1,795 1,795	1,795 1,795
(5)	4	693	693 1,102	1,102 1,379	1,379 1,379	1,379 1,795	1,795 1,795	1,795 1,795
(6)	5		693	693 1,102	1,102 1,379	1,379 1,379	1,379 1,795	1,795 1,795
(7)	6			693 693	1,102 1,102	1,379 1,379	1,379 1,379	1,795 1,795
(8)	Total Nuclear GWh	1,386 2,772	3,590 5,101	6,348 7,311	7,720 7,997	9,106 9,938	9,938 10,354	10,770 10,770

Proportion of Nuclear Energy Displaced by HVDC Energy

		5	6	7	8	9	10	11 to 29
(9)	Ratio: $\frac{\text{HVDC GWh}}{\text{Nuclear GWh}}$	0.86 0.86	0.99 0.93	0.92 0.96	0.91 0.88	0.77 0.71	0.71 0.68	0.65 0.65

TABLE 4.9

Nuclear Units -

Incidence of Capital Expenditure as a Percentage of

Total Capital Costs

Year	1	2	3	4	5	6	7
Case A	10	20	30	35	5	-	-
Case B	4	16	24	29	17	7	3

Notes: In "Case A" the commissioning date is assumed to be the 1st January year (5).

In "Case B" the commissioning date is assumed to be the 1st July year (6).

TABLE 4. 10

INCIDENCE OF CAPITAL EXPENDITURE OF NUCLEAR UNITS

IN $ MILLIONS

CASE A

Up to end of Year	Nuclear Units No. 1 & 2	3 & 4	5	6	Total
0.5	49.14				49.14
1	49.14	49.14			98.28
1.5	98.28	49.14			147.42
2	98.28	98.28	24.57		221.13
2.5	147.42	98.28	24.57	24.57	294.84
3	147.42	147.42	49.14	24.57	368.55
3.5	171.36	147.42	49.14	49.14	417.06
4	172.62	171.36	73.71	49.14	466.83
4.5	*25.2	172.62	73.71	73.71	345.24
5	23.94	*25.2	85.68	73.71	208.53
5.5		23.94	86.31	85.68	195.93
6			*12.6	86.31	98.91
6.5			11.97	*12.6	24.57
7				11.97	11.97
7.5					0

Note: * Commissioning date 1st day of the six month period.

TABLE 4.11

INCIDENCE OF CAPITAL EXPENDITURE OF NUCLEAR UNITS IN $ MILLIONS

CASE B

Up to end of Year	Nuclear Units No.				Total
	1 & 2	3 & 4	5	6	
-1.0	14.42				14.42
-0.5	14.42	14.42			28.84
0.0	57.66	14.42			72.08
0.5	57.66	57.66	7.21		122.53
1.0	86.48	57.66	7.21	7.21	158.56
1.5	86.48	86.48	28.83	7.21	209.00
2.0	100.9	86.48	28.83	28.83	245.04
2.5	108.1	100.9	43.24	28.83	281.07
3.0	64.86	108.1	43.24	43.24	259.44
3.5	57.66	64.86	50.45	43.24	216.21
4.0	28.84	57.66	54.05	50.45	191.0
4.5	(1) 21.62	28.84	32.43	54.05	136.94
5.0	14.42	(1) 21.62	28.83	32.43	97.3
5.5	7.2	14.42	14.42	28.83	64.87
6.0		7.2	(1) 10.81	14.42	32.43
6.5			7.21	(1) 10.81	18.02
7.0			3.6	7.21	10.81
7.5				3.6	3.6
8.0					0.0

Note: (1) Commissioning date first day of the six-month period.

(2) The construction period is eighteen months longer than Case A and therefore contracts are awarded eighteen months earlier than Case A or HVDC scheme. This time period is shown in the table as years -1 to 0.

TABLE 4.12

ANNUAL CASH FLOWS $ MILLIONS

NET PRESENT VALUED TO FIRST DAY YEAR 5

CASE A

Six Months Up To End of Year	Capital Cost in $	O. & M. Costs	Fuel Cost	Total Costs	Total NPV Cost
0.5	49.14	-	-	49.14	68.7
1.0	98.28	-	-	98.28	130.81
1.5	147.42	-	-	147.42	187.37
2.0	221.13	-	-	221.13	267.56
2.5	294.84	-	-	294.84	340.54
3.0	368.55	-	-	368.55	405.41
3.5	417.06	-	-	417.06	437.91
4.0	466.83	-	-	466.83	468.83
4.5	345.24	19.66	4.16	369.05	352.26
5.0	208.53	39.32	8.32	313.18	284.71
5.5	195.93	39.32	10.77	246.02	213.5
6.0	98.91	49.15	15.30	163.36	135.02
6.5	24.57	58.98	19.04	102.59	80.93
7.0	11.97	58.98	21.93	92.88	69.78
7.5	0	58.98	23.16	82.14	58.91
8.0		58.98	23.99	82.97	56.67
8.5		58.98	27.32	86.30	56.27
9.0		58.98	29.81	88.79	55.13
9.5		58.98	29.81	88.79	52.63
10.0		58.98	31.06	90.04	50.83
$\sum_{11}^{29}$		$\sum_{11}^{29}$ 117.96	$\sum_{11}^{29}$ 64.62	$\sum_{11}^{29}$ 182.58	933.17
				TOTAL	4,707.01

An annuity of $518.56M at 10% in twenty-five years would give the above NPV $4.707.01M.

TABLE 1.13

ANNUAL CASH FLOWS IN $ MILLIONS
NET PRESENT VALUED TO FIRST DAY YEAR 5

CASE B

Six Months Up To End of Year	Capital Cost in $	O. & M. Costs	Fuel Cost	Total Costs	Total NPV Cost
-1.0	14.42	-	-	14.42	23.22
-0.5	28.84	-	-	28.84	44.41
0.0	72.08	-	-	72.08	105.24
0.5	122.53	-	-	122.53	171.30
1.0	158.56	-	-	158.56	211.04
1.5	209.00	-	-	209.00	265.64
2.0	245.04	-	-	245.04	296.5
2.5	281.07	-	-	281.07	324.64
3.0	259.44	-	-	259.44	285.38
3.5	216.21	-	-	216.21	227.02
4.0	191.00	-	-	191.00	191.00
4.5	136.94	6.53	3.47	146.94	140.25
5.0	97.3	13.06	6.93	117.29	106.63
5.5	64.87	13.06	8.98	196.02	170.11
6.0	32.43	16.32	12.75	61.5	50.83
6.5	18.02	19.53	15.87	53.42	42.14
7.0	10.81	19.53	18.28	48.62	36.53
7.5	3.6	19.53	19.30	42.43	30.43
8.0	0.0	19.53	19.99	39.52	26.99
8.5		19.53	22.77	42.3	27.58
9.0		19.53	24.85	44.38	27.56
9.5		19.53	24.85	44.38	26.30
10.0		19.53	25.89	45.42	25.64
$\sum_{11}^{29}$		$\sum_{11}^{29}$ 39.06	$\sum_{11}^{29}$ 53.86	$\sum_{11}^{29}$ 92.92	410.61
				TOTAL	3,266.99

An annuity of $359.92 Millions at 10% in twenty-five years would give the above total NPV cost of $3,266.99 Millions.

TABLE 4 - 14

NUCLEAR ENERGY COST WHICH CAN BE REPLACED BY HVDC ENERGY

CASE "A"

Six months up to end of Year	Annuitised Total Nuclear Energy Costs in $ M	Proportion of Nuclear Energy replaced by HDVC	Cost of Nuclear Energy replaced by HVDC in $ M	Replacement NPV Costs in $ M
4.5	259.28	0.86	222.98	212.83
5	259.28	0.86	222.98	202.71
5.5	259.28	0.99	256.69	222.76
6	259.28	0.93	241.13	199.30
6.5	259.28	0.92	238.54	188.18
7	259.28	0.96	248.91	187.01
7.5	259.28	0.91	235.95	169.22
8	259.28	0.88	228.17	155.84
8.5	259.28	0.77	199.65	130.76
9	259.28	0.71	184.09	114.30
9.5	259.28	0.71	184.09	109.11
10	259.28	0.68	176.31	99.53
$\sum_{11}^{29}$	$\sum_{11}^{29}$ 518.56	$\sum_{11}^{29}$ 0.65	$\sum_{11}^{29}$ 337.06	1722.73
			Total NPV Cost	3714.28

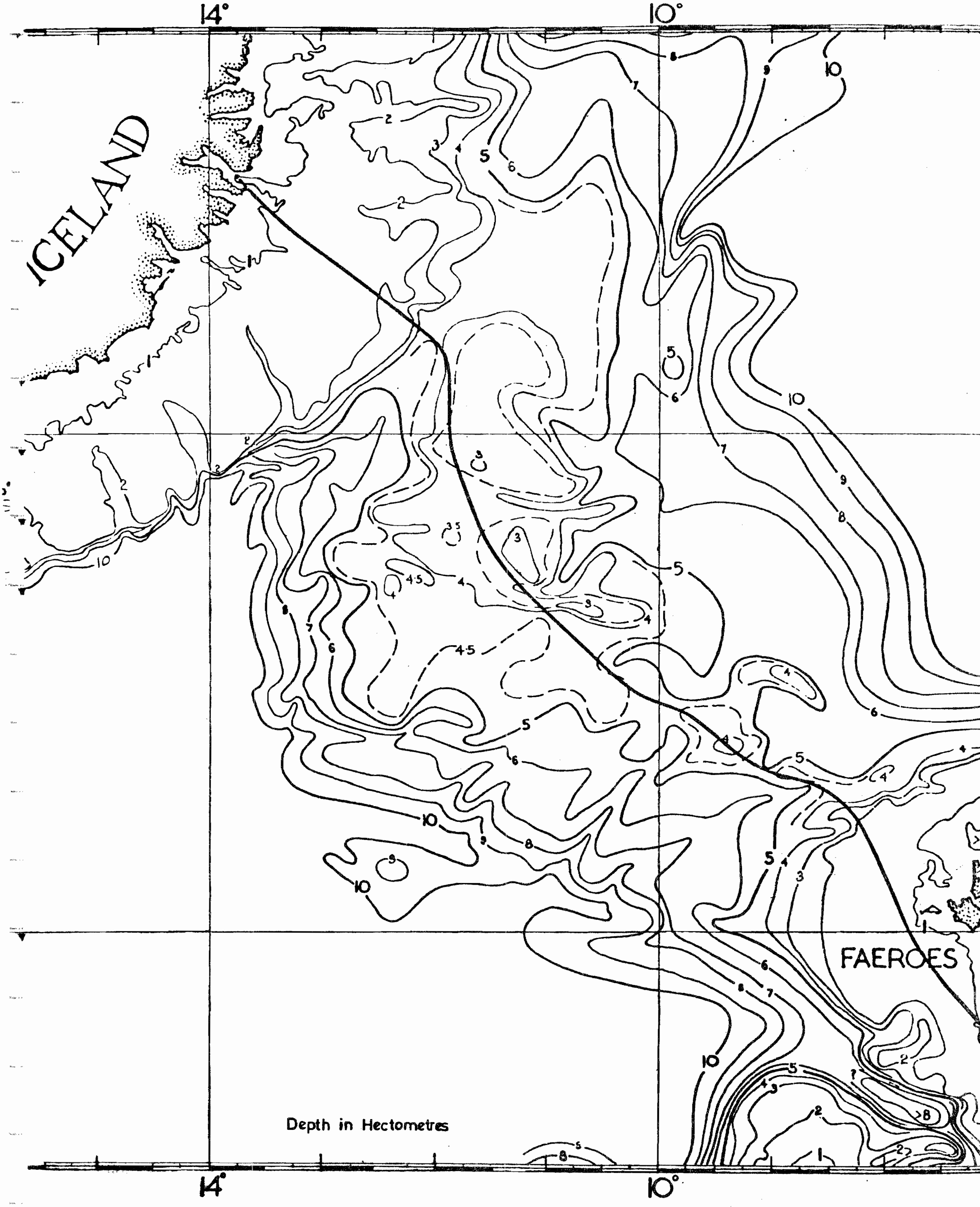
TABLE 4.15

NUCLEAR ENERGY COST WHICH CAN BE REPLACED BY HVDC ENERGY

CASE B

Six Months Up To End of Year	Annuitised Total Nuclear Energy Costs In $ Millions	Proportion of Nuclear Energy Replaced By HVDC	Cost of Nuclear Energy Replaced by HVDC in $ Millions	Replacement NPV Costs in $ Millions
4.5	179.96	0.86	154.77	147.72
5.0	179.96	0.86	154.77	140.70
5.5	179.96	0.99	178.16	154.61
6.0	179.96	0.93	167.36	138.33
6.5	179.96	0.92	165.56	130.61
7.0	179.96	0.96	172.76	129.8
7.5	179.96	0.91	163.76	117.45
8.0	179.96	0.88	158.36	108.16
8.5	179.96	0.77	138.57	90.35
9.0	179.96	0.71	127.77	79.33
9.5	179.96	0.71	127.77	75.73
10.0	179.96	0.68	122.37	69.08
29.0	29		29	
Σ	Σ 359.92	0.65	Σ 233.95	1,033.82
11.0	11		11	
			Total NPV Cost	2,415.69

POSSIBLE SUBMARINE CABLE ROUTE BETWEEN ICELAND AND FAEROES



POSSIBLE SUBMARINE CABLE ROUTE BETWEEN FAEROES AND SCOTLAND

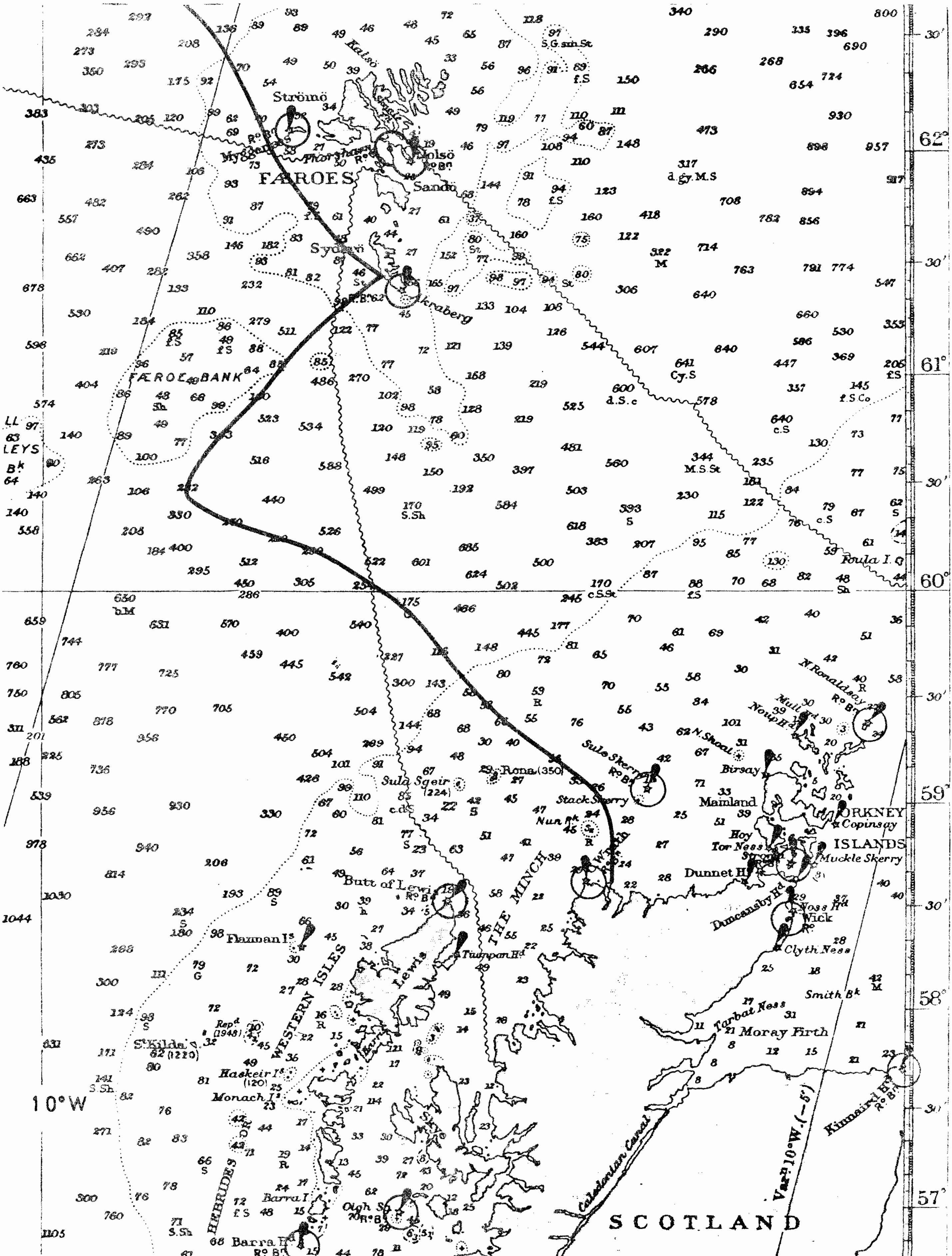


Figure 4.3

COMPOSITION OF SEA-BED

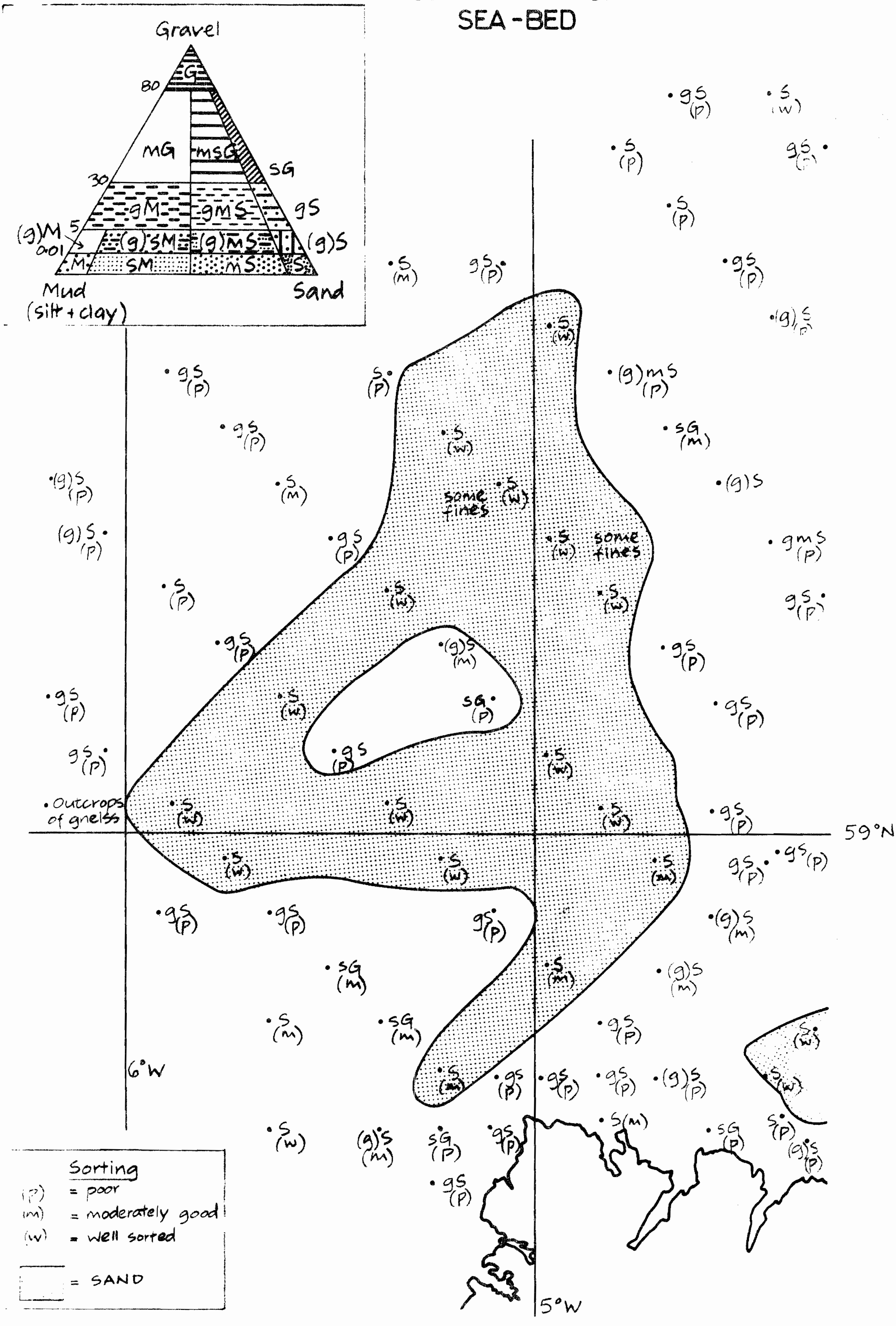
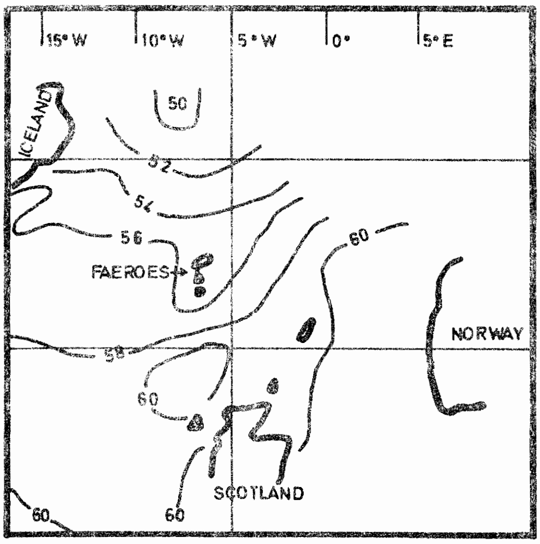
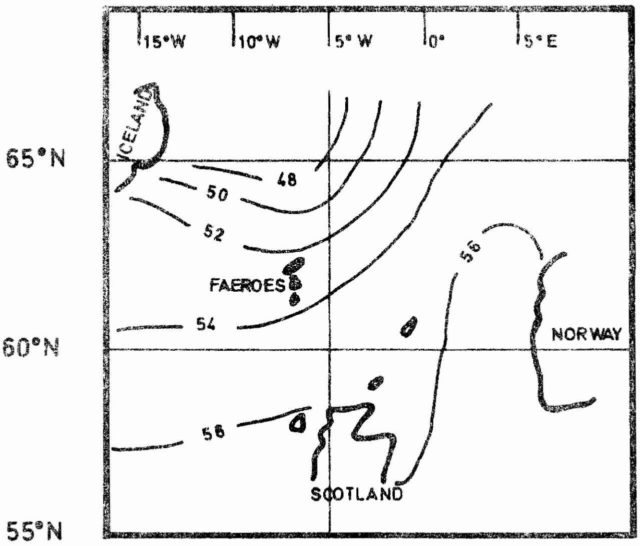


Figure 4.4

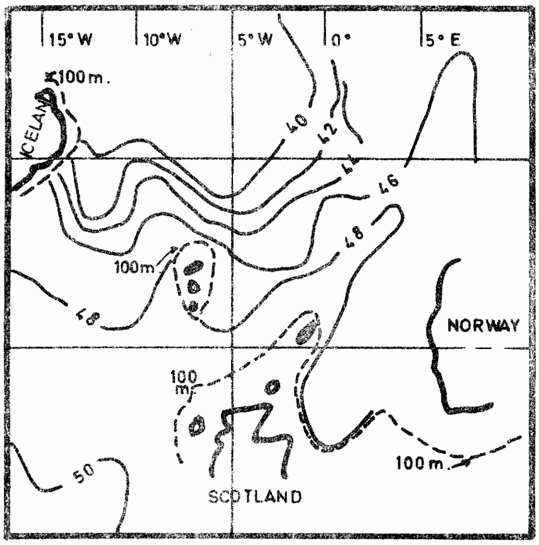
MAXIMUM AND MEAN SEA TEMPERATURES IN °F AT VARIOUS DEPTHS



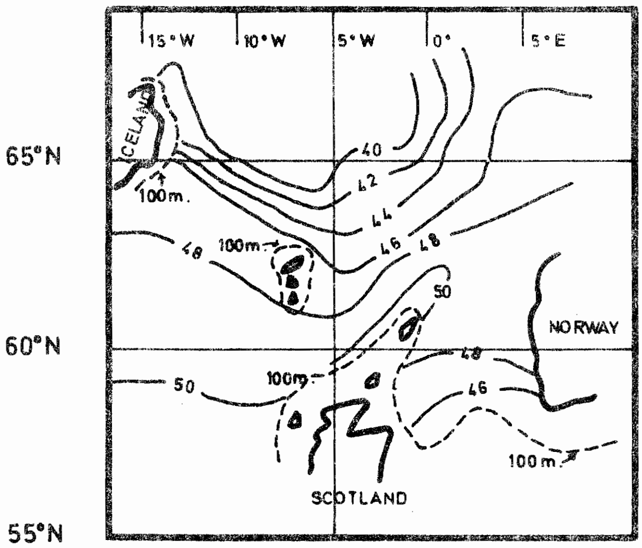
Maximum August surface temperature



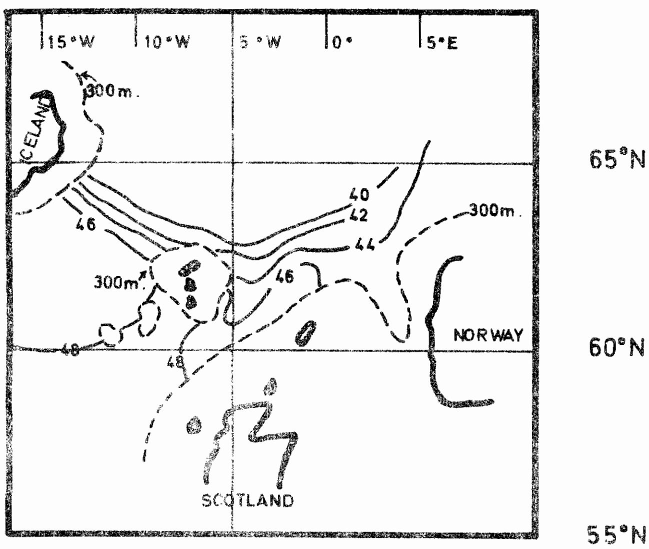
Mean August surface temperature



Mean July - Sept. temp. at 100m. depth



Mean Oct. - Dec. temp. at 100m. depth



Mean Jan. - Dec. temp. at 300m. depth

SCHEMATIC DIAGRAM OF AN HVDC SUBMARINE TRANSMISSION SCHEME (1330 amps, ± 250 kV, 2000 MW)

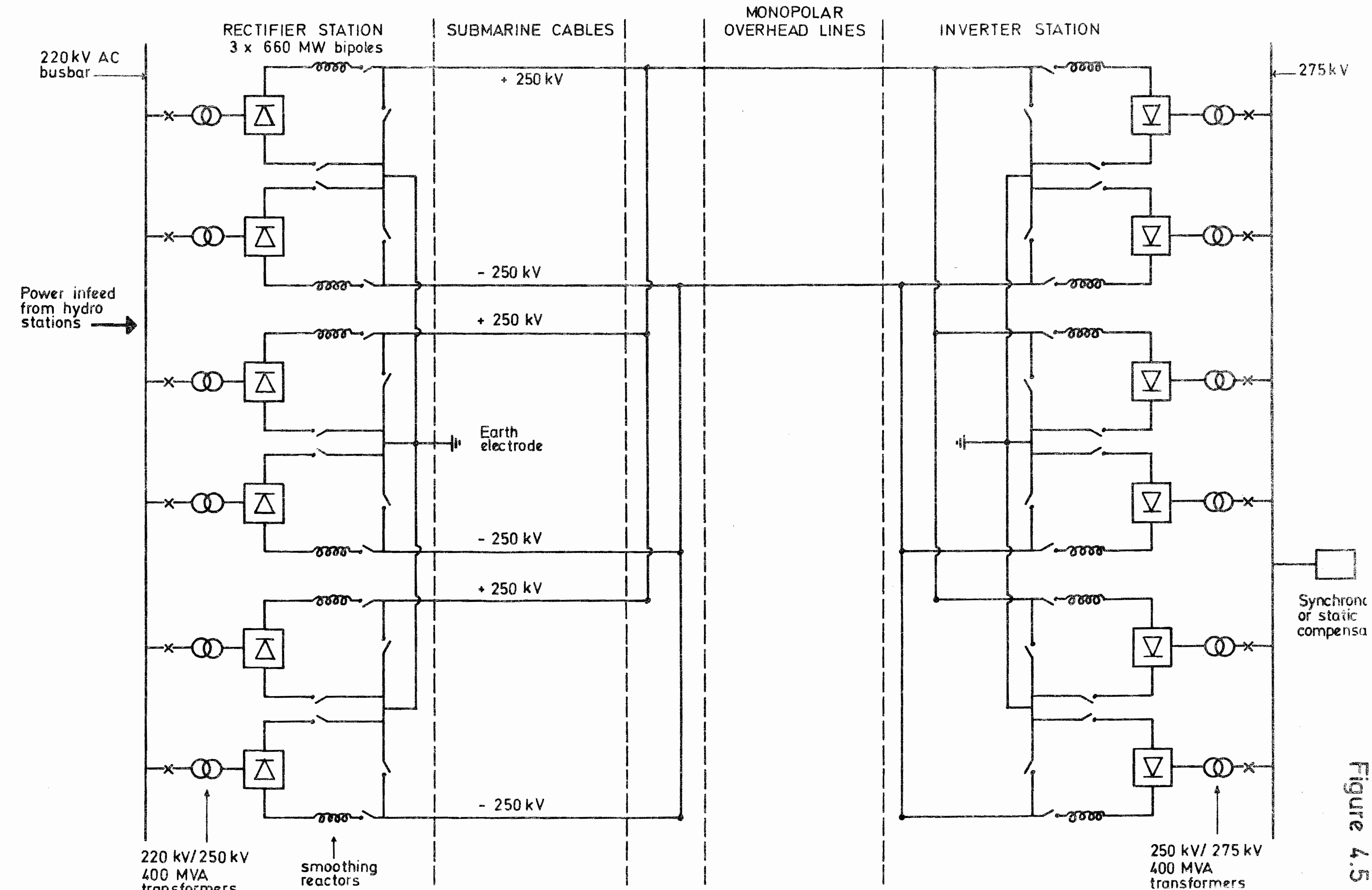


Figure 4.5

5 CONCLUSIONS

5.1 Overhead HVDC Transmission versus AC

From Section 3.4, it can be seen that it is not economic to transmit 1,000 MW, 8,000 GWh over a distance of 400 km. The only justification for installing DC would be if one of the technical criteria listed in Section 2.5 overruled the economic case against it.

5.2 HVDC Submarine Transmission

There is an economic case for the export of 2,000 MW and 16,000 GWh from Iceland if energy can be supplied at 7 mills/kWh.

If the cost of energy is above this figure, but below 16 mills/kWh, a more detailed examination of the problem would be required in collaboration with the Scottish Electricity Boards. This work should take account of intangible benefits.

The technical feasibility of the project is dependent on whether the depth of water across the deep trough between Faroes and Scotland is less than 1,000 metres.