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PRESENT LIMITS OF VERY LONG DISTANCE TRANSMISSION SYSTEMS

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☆ See CONCLUSIONS PAGE 8

Summary

Energy resources available at sites far away from load centres can become competitive as a result of the present high cost of the energy available at nearby sites, and of the recent development of transmission technology.

The paper gives a through analysis of the conditions that determine the competitiveness of electric energy transmission over very-long-distance (VLD) transmission exceeding 2000 kilometers, by means of technical and economic assessments, based on the present state of the art and on the developments expected in the short term.

Investment cost, efficiency and reliability of VLD transmission system (TS), both AC and DC, have accordingly been determined.

A further stage deals with the optimization of system variables, based on the minimum cost of the energy delivered, which renders the characteristics of the transmission system independent of those of the receiving system. The consequences for the receiving system of the different reliability of the various TS considered, are taken into account by adding risk-cost.
Based on this, the competitiveness limits of remote energy resources are then determined as a function of:

- The cost at the origin of the remote resources
- The power to be transmitted and relevant load factor
- The size of the remote generating system as compared to that of the receiving system
- The value of the energy at the receiving system

Key-words: transmission, long distance, reliability, economics.

1. Introduction

Some parts of the world have hydraulic resources that can be exploited at low cost for the production of electricity. Example of this are the Amazon basin, the River Zaire (Inga), South-West of China, etc.
There are also coalbeds that could be exploited in the vicinity of the mines to provide low-cost electric power.
One of the reasons why these resources have never been utilized is their great distance from any consumer areas.
The increased cost of electricity generated by power stations located in consumer areas plus the progress achieved in transmission technology means that the exploitation of these remote resources is now becoming competitive.
We therefore decided to produce a technical and economical assessment that would, as far as possible, have general validity, and serve as an instrument for the rapid evaluation of the competitiveness of remote energy sources, at the same time showing that great distances, to-day, no longer represent a fundamental obstacle to the exploitation of those sources.

2. Main Assumptions for Remote Energy Sources

Two different types of remote energy sources have been considered, hydro plants and mine-mouth coal-fired thermal plants, and for both of them two different capacity factors and various energy costs have been investigated.
More precisely, the hydro source was characterized by a fixed cost (1) varying from 750 to 2000 $/kW (2) referred to its capacity. With reference to a plant life T of 50 years and to an annual interest rate i = 0,1 ($a_{\overline{50}|0,1} = 0{,}1$), the cost of the energy produced therefore assumed values ranging from 8.5 to 22.8 mills/kWh when considering a capacity factor of 1 and from 14.4 to 38.5 mills/kWh when considering a capacity factor of 0.6.

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(1) This cost was assumed to include any expense due to extra machinery (installed for the purpose of having the capacity considered always available), as well as to operation and maintenance.

(2) All the costs in the report are in 1982 US$.

Mine-mouth, coal-fired thermal plants were assumed to have a running cost of 10 (in some cases 20) mills/kWh and a fixed cost of 550 $/kW. The corresponding cost of energy (with $\alpha_{25|0.1}$ = 0.11) varied from 19 mills/kWh when considering "base duty" (an overall availability of 0.76 being assumed for the thermal units) to 22.8 mills/kWh when considering "intermediate duty" (capacity factor ~ 0.6).
The wide range of costs adopted both for hydro and for (mine-mouth) coal production reflects the purpose of the study of examining the competitiveness of remote energy sources located in different countries and having quite different characteristics (see Section 5).

3. Main Assumption for the Transmission Schemes

Since the main purpose of the study was that of evaluating the cost of transmitting electricity over VLD, the basic transmission scheme selected was of the HVDC type (see Section 3.1), for which different values of delivered power P (e.g. 2.5, 5, 10 GW) and length L (up to 7000 Km), were considered. For the same values of P, but only for the shortest distances (up to 4000 Km) the possible use of an UHV a.c. (60 Hz) transmission scheme was also investigated (see Section 3.2).
It should be noted that the evaluations for a.c. and d.c. transmission are not intended for the purpose of choosing between the two different solutions - which would, in any case, call for a more detailed analysis and the taking into account of other factors not considered here- but simply to show that both types of long-distance transmission are feasible.

3.1 HVDC Transmission Scheme

The basic d.c. transmission scheme consisted of two bi-poles connecting the Sending End (SE) with the Receiving End (RE) through two bi-polar lines (fig. 1).

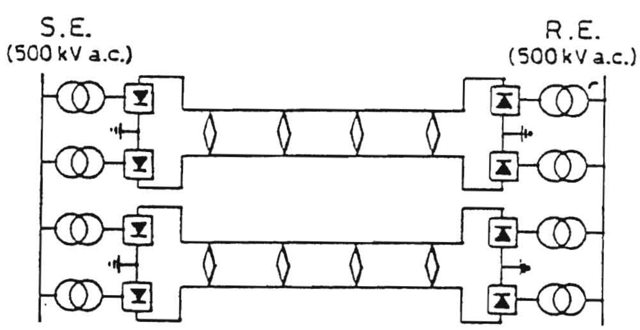

Fig. 1 - Basic HVDC transmission scheme considered

The following design criteria were adopted:

3.1.1 For each pole two 12-pulse groups in series were taken as basic configuration. For the highest voltage and power values, the solution of three 12-pulse groups in series was also considered.

3.1.2 The a.c. voltage level at the converter station was assumed to be 500 kV for cost reference. The reactive power required was assumed to be supplied: at the RE by a.c. filters, shunt-capacitor banks, and var controllable equipment; at the SE, by a.c. filters and by generators.

3.1.3 Each bi-polar line was designed to carry the full power P, in emergency conditions. These conditions refer to the permanent outage of one bi-polar line, transmission of the total power P being achieved trough the paralleling of the converter bi-poles at each terminal. The possibility was also assumed of paralleling station poles having the same polarity in the event of loss of one line pole or of two poles of different lines.

3.1.4 The voltage level (± V) and cross-section (S) of the transmission bi-poles were chosen as indicated in section 5.2.

3.2 EHV and UHV a.c. Transmission Scheme

The basic a.c. transmission scheme consisted of two lines connecting the SE and RE.
Autotransformers at RE and SE, Intermediate Substations (IS) located every 400 Km., series and shunt compensation, were provided (fig. 2).

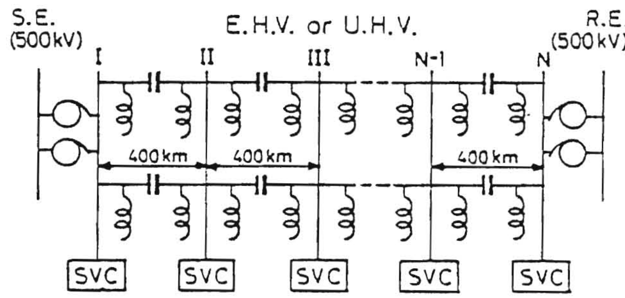

Fig. 2 - Basic EHV or UHV a.c. transmission scheme considered

The following design criteria were adopted:

3.2.1 A reserve margin of 30% was adopted for the SE and RE autotransformers; a voltage level of 500 kV was assumed, for cost reference, both at the SE and RE. The voltage level of the lines (chosen in the EHV-UHV range) and the phase cross section S (1) were optimized as indicated in section 5.3.

3.2.2 Each 400 km line-section was equipped with 30% series compensation.

3.2.3 The optimum amount of SVC devices (of the "Controlled Reactor - Fixed Capacitor" type) to be provided at each substation, was determined so as to assure voltage control and stability. In particular voltage control and steady-state stability were assured for all the operating conditions envisaged when all system in service or when one major element (e.g. one line section) was out; transient stability was ensured for single-phase fault on one line section (cleared after 0.1 s by definitive tripping) with:

the system charged at full capacity P and no major element out

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(1) Hereafter in this paper S is used to mean the aluminium cross-section (only).

- the system charged at 3/4P and one line section out
- the system charged at 1/2P and two non parallel line sections out.

4. Performance (availability) Data of the Transmission Systems

Starting from unavailability data of the various component (see Section 4.1, 4.2, and 4.3) the overall availability of the various transmission schemes was evaluated (see 4.4. and 4.5.) in terms of durations (p.u.) in which the full capacity P or reduced fractions of it could be transmitted. The expected frequency of the transition from one capacity level to the other was also evaluated.

4.1. HVDC Station Unavailability

The performance data (forced outage rate p, frequency λ and repair time r) of the ac/dc station equipment, were taken from manufacturers figures and from published statistics [1] [2] [3]. In selecting the final figures account was taken of the continuos progress in this field.
These unavailability data were utilized to evaluate (Markov process) the unavailability of the valve groups, of the poles and bi-poles, as shown, in a single case, in Table I. To achieve these values, sufficient spares were assumed and their cost was included in the ac/dc station cost.

Table I: Unavailability of ac/dc converters

outage of:	forced unavailability (p.u.)
1 valve group	17.8×10^{-4}
1 pole	4.3×10^{-4}
1 bi-pole	0.7×10^{-4}

4.1.1 It should be noted that, although, in the course of the study, the above figures were used for reference purposes, a more pessimistic assumption in respect of equipment unavailability (i.e., three-times the above values) was also examined. Moreover, for this second assumption, much greater frequency (1/yr) for the forced outage of the entire bi-pole was taken, thus increasing the dynamic risk, as shown in Section 6.3.

4.2 EHV and UHV a.c. Substation Unavailability

No detailed calculations were made of substation unavailability. It was simply assumed that, given sufficiently redundant schemes, the unavailability of each line bay or transformer bay could be of the order of one outage every 50 years of an average duration of 3 hours.
Transformers, reactors and SVCs were assumed - sufficient spares being provided - to have a negligible effect on transmission unavailability as compared with that of line outages.

4.3 Transmission Line Outage Data

The set of forced unavailability data adopted for a.c. transmission lines corresponded to rather severe (1) environmental conditions. For countries with more favourable conditions the hypothesis was therefore conservative.
D C lines were assumed to suffer the same repair time (hours/outage), but with only 2/3 of the frequency of single-phase outages on a.c. lines. Moreover it was assumed that transients faults did not cause any outage of the pole affected.

The frequency of permanent, multi-phase outages (including tower collapse) was, on the contrary, assumed to be the same for a.c. and d.c. lines.

With reference to 100 km of line, these assumptions resulted in the performance data shown in Table II.

Table II - Performance data of a.c. and d.c.lines

Type of line	Type of fault	Type of outage	λ Outages/year	r Hours/outage	U Hours/year
a.c.	Transient (single phase)	line	3	-	-
	Permanent (single phase)	line	0.9	13	12
	Permanent (multi phases)	line	0.1	50	5
d.c.	Transient (one pole)	no outage	2	–	-
	Permanent (one pole)	any of the 2 poles	0,6	13	8
	Permanent (two poles)	bipole	0.1	50	5

4.4 Overall HVDC Transmission Reliability

By combining the unavailabilities of the converter poles with those of the transmission poles (or bipoles) probabilities were obtained for the various power levels that can be transmitted over the bi-pole.

One example of results is given in Table III for the case of two 12-pulse groups per pole and two bi-polar lines.

Tab. III - HVDC Transmission Availability

Transmission Capacity Available	Availability (p.u.x10^{-4})			
	L= 1000Km	L= 2000Km	L= 4000Km	L= 7000Km
P	9840.3	9836.7	9819.6	9773.9
7/8P	140.5	139.8	139.9	138.8
6/8P	17.6	17.6	17.9	18.0
4/8P	1.0	4.2	17.0	52.4
0	0.3	1.3	5.5	16.8

(1) The set of performance data was taken from the statistics [4] of the 400-kv a.c. lines of a region in the north of Italy, where several lines cross mountainous areas.

The expected frequency of the transition from one capacity level to the others was also evaluated: of particular importance for dynamic-risk evaluation (see Section 6) was the possibility of sudden loss of P/2 or of P (one lines being out, a permanent fault occurs on one or both the poles of the second lines). The frequency of these events was evaluated at 4.35/yr (loss of P/2) and 0.6/yr (loss of P) for the case of L = 7000 km; for shorter distances, it decreases roughly with the square of L.
For the more pessimistic assumption on converter availability (section 4.1.1), loss frequency in respect of P/2 was increased by roughly 2 events/yr for any L.

4.5 Overall EHV and UHV a.c. Transmission Reliability

In the case of a.c. solutions, a calculation similar to that shown in section 4.4. was made by combining the performance data of a.c. substations and line sections.

In making this calculation the following maximum power transits were adopted: full capacity P when no line section is out; 3/4 P when one line section is out; P/2 when two line sections (not in parallel) are out; P=0 when two parallel sections are contemporaneously out. The above limitations to 3/4 P and P/2, even if not required for steady-state operation, were, however, adopted in order to prevent instability problems (as indicated in Section 3.2.3).

Typical results of transmission availability are given in Table IV.

Table IV - EHV-UHV a.c. Transmission Availability

Transmission Capacity Available	Availability (p.u. $x10^{-4}$)		
	L= 1000Km	L= 2000Km	L= 4000Km
P	9570.7	9182.7	8431.5
3/4P	410.5	787.1	1444.0
1/2P	5.8	27.5	117.1
0	3.2	3.7	7.4

As for d.c. transmission, the expected frequency of transitions from one state to the others was also evaluated. The most critical case, in respect of dynamic risk, was found to be the sudden loss of 3/4P (one line section being out, a fault occurs on the second line section of the same trunk): annual frequency was 2.4/1.3/0.6 for 4000,2000 and 1200 km respectively.

5. Transmission Cost Data and Optimization Studies

On the basis of the cost of the energy produced at the remote source (section 2) and of the cost-data assumed for the transmission equipment (section 5.1), the optimum voltage level V and conductor cross-section S of the a.c. and d.c. lines were determined by minimizing the unit cost of the energy delivered at the RE, generating cost included.

5.1 Cost Data for Transmission Equipment

Cost data for the various equipments of the d.c. and a.c. transmission systems were taken from manufacturers' figures and from data on existing plants. Particular care was taken to ensure these costs were as much homogeneous as possible , as regards both currency (all costs were expressed in 1982 US dollars) and variation with voltage and rated capacity.
Subsequently, for the purpose of optimization studies (see 5.2.), formulae of the type given in [5], [6] and [7] were derived from the above costs by expressing the cost of substations (both a.c. and d.c.) as a function of their voltage, structure, and total rated capacity, and the cost of the lines (both a.c. and d.c.) as a function of their length, voltage, phase (or pole) conductor cross-section and number of sub-conductors.

Example of the cost adopted are shown in Tab. V.

Table V - Example of Cost of Lines and Substations

a.c./d.c. conversion substations (SE+RE, one bipole, 2.5 GW, ± 900 kV, two 12-pulse groups per pole, spares and reactive compensation included)	207 $/kW
d.c. bi-polar line (±900kV, aluminium pole cross-section=4x585mm^2, right-of-way cost not included)	228 k$/Km
a.c. SE+RE substations (5000 MW, 500/1050 kV, autotransformers and spares included)	160 M$
a.c. transmission line (1050 kV, phase cross section =8x280 mm^2 right-of-way cost not included)	374 k$/Km

5.2 Optimization of the HVDC Transmission System

5.2.1 For each value of the power P delivered at the RE and of the transmission length L, the optimum values were determined for voltage V (kV) and pole cross-section S (mm^2) by minimizing the unit cost (mills/KWh) of the energy delivered at the RE. Thus, the unit cost c_{RE} of energy delivered was expressed as:

$$c_{RE} = \frac{1}{Ph_u} \cdot \left[a' (C_c + C_L) + a'' c_G \frac{(P + \Delta P)}{k} + c_F (Ph_u + \Delta Ph_p) \right]$$

where:

- Ph_u = total energy (kWh) delivered at the RE (h_u represents the load factor of the RE rated power P and was varied from 3760 to 5200 hrs/yr in the case of remote hydro; from 7400 to 5200 hrs/yr in the case of remote thermal source)

- $a'(C_c + C_L)$ represents the annuity (T = 25 years, i = 0.10 per year) of the capital cost C_c of the SE and RE a.c./d.c. conversion stations and of the cost C_L of the two line bi-poles (C_c and C_L were expressed as a function of V,S,P for purpose of optimization)

- $a'' c_G (P + \Delta P)/k$ represents the annuity (T = 25 years or 50 years respectively in the case of thermal and hydro generation) of the capital cost $c_G (P + \Delta P)/k$ of the generating capacity installed at the SE, both for supplying the power P and the power losses at peak ΔP (in the case of thermal generation, a factor k = 0.9 was introduced, since the transmission capacity P was limited to 0.9 of the generating capacity installed (1))

- $c_F Ph_u$ represents the running cost (pratically the fuel cost) in producing the energy delivered

- $c_F \Delta Ph_p$ represents the cost of energy losses (h_p varies according to the variation of h_u)

- the units cost c_F was assumed to be zero for hydro and 10 or 20 mills/kWh for thermal production.

5.2.2 When minimizing c_{RE} as a function of V and S, some constraints were taken into account namely:

- aluminium cross-section of each subconductor higher than 250 mm^2 for mechanical reasons;

- audible noise, at the right-of-way border, lower than 50 dB-A (fair weather) and R.I. (500 kHz) lower than 60 dB (above 1 μV/m, fair weather) (2);

- maximum voltage drop ≤ 20% even in emergency conditions (outage of one bi-polar line).

5.3 Optimization of the EHV and UHV A C Transmission Schemes

5.3.1 For each value of the power P delivered at the RE and of the transmission length L, the optimum values of voltage V, of phase cross-sections S and of subconductors number n (which influence the electric parameters) were determined by a procedure similar to that described for d.c. transmission. Also in this case, the cost of substations was expressed as a function of V and P, and the cost of lines as a function of V, S and n.

5.3.2 In the course of the optimization, the following constraints were considered:

- aluminium cross-section of each sub-conductor higher than 250 mm^2 for mechanical reasons

- audible noise, at the right-of-way border, lower than 60 dB.A (wet conductor) and R.I. (500kHz) lower than 70 dB (above 1μV/m, foul weather) (2).

5.3.3 For the optimization, the amount of SVC to be installed at the SE, RE and IS was determined by the design criteria established in Section 3.2.3: the maximum (inductive) reactive power requirement was determined by steady-state operation at no-load, while the minimum inductive (or maximum capacitive) compensation was required to ensure transient stability. When of the inductive type - such as in most cases and particularly in all cases with L > 2800 Km-the latter compensation was obtained by line-connected fixed-reactors.

(1) It was assumed that, owing to the large unavailability of the generating sets, the maximum available generating capacity will only rarely exceed 90% of the total installed capacity.

(2)The relatively high limits have been accepted on the assumption that the areas crossed by lines are uninhabited.

5.4 Results

The most significant results, obtained by means of the above described procedure, are shown in Table VI and VII and in Fig.s 3, 4 and 5.
Table VI shows a synthesis of the results and in particular the range of voltages and pole/ phase cross-sections obtained by the optimization procedure (P is the transmission capacity of two lines). With reference to the highest voltage levels, not yet planned for existing projects, it may be observed that feasibility has been proved by various research schemes and that, even if the use of voltage considerably lower (20%) than those shown should be decided on, unit cost would increase by only a few per cent. Only the voltage levels > 1.200 kV calculated for a.c. transmission of 10 GW and L > 2000 km, cannot be reduced due to stability requirements - or else, more than 2 lines could be used.
Fig.s 3,4 and 5 show the unit cost c_{RE} of energy delivered as a function of transmission length.
In the same Fig.s a horizontal line indicates the unit cost c_{SE} of the electricity produced at the SE, thus evidentiating the remaining part, $c_{RE} - c_{SE}$, due to transmission costs (losses included) that of course increases with L. The cost-of-risk c_R, as evaluated in the following section 6, has also been added and shown by dotted lines.

Table VI - Range of voltages, pole/phase cross sections and number (n) of subconductors for transmission of power P.

P	D.C. TRANSMISSION L = 1000 - 7000 Km			A.C. TRANSMISSION L = 1200-4000 Km		
(GW)	V (kV)	S$_2$ (mm^2)	n -	V (kV)	S$_2$ (mm^2)	n -
10	± 1000/ ± 1200	3400/ 4000	6	1200/ 1500	3750/ 4000	10/ 16
5	± 800/ ± 1000	2350/ 2700	4	1050/ 1200	2200/ 2500	8/ 10
2.5	± 600/ ± 800	1450/ 1850	4	800/ 1050	1550/ 2000	6/ 8

For one of the cases examined a more detailed break-down of c_{RE} (cost of risk not included) is shown in Table VII with reference both to a.c. and d.c. transmission.

Table VII - Unit cost c_{RE} (5 GW, load factor = 1, L = 2000 Km, hydro source at 2000 $/kW)

	D.C. TR (1) mills/kWh	A.C. TR (2) mills/kWh
GENERATION AT SE	22.80	22.80
SE + RE SUBSTATIONS	2.61	0.40
INTERMEDIATE SUBSTAT.	-	0.22
LINES	2.29	3.76
REACTIVE COMPENSATION	-	0.99
LOSSES	1.95	1.98
TOTAL	29.65	30.15

(1) Two d.c. bi-polar lines, ± 900 kV, 4x537 mm^2, two converters 2.5 GW

(2) Two a.c. lines 1050 kV, 8x280 mm^2, 30% series compensation, 5000 Mvar shunt reactors, 17500 Mvar shunt controlled compensation, four Intermediate Substations.

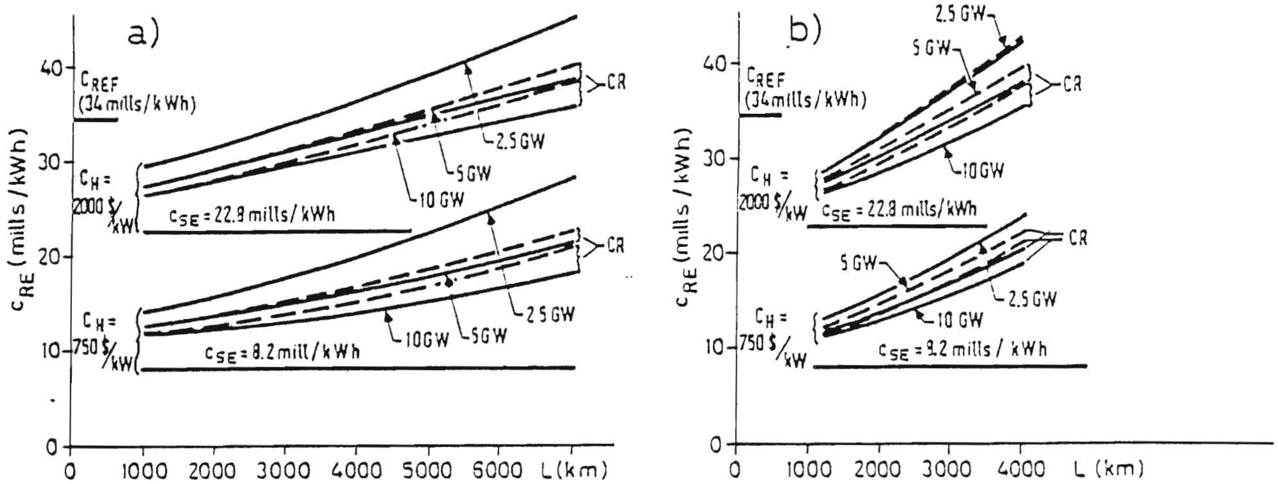

Fig. 3 - Unit cost c_{RE} of the energy delivered at RE for D C (a) or A C (b) transmission of P x 8760 GWh/yr from a remote hydro source of fixed cost C_H.

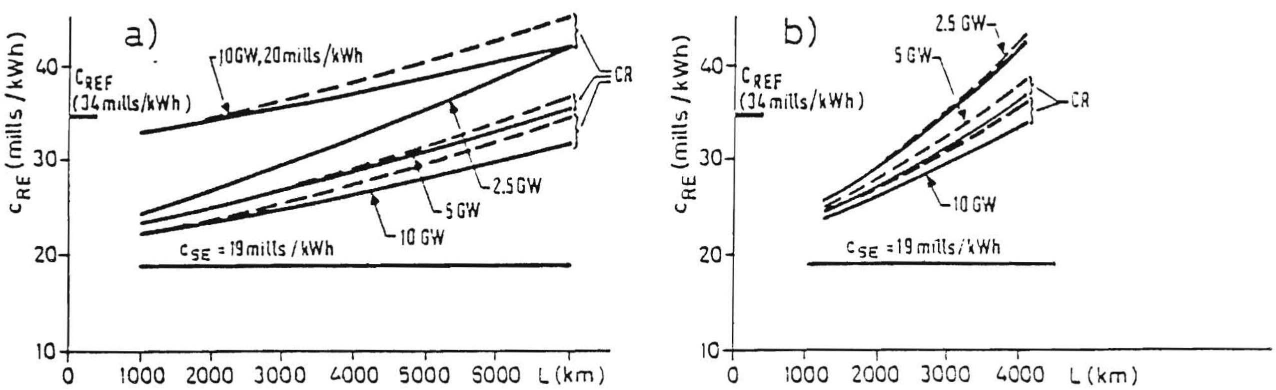

Fig. 4 - Unit cost c_{RE} for D C (a) or A C (b) transmission of P x 7400 GWh/yr from a remote source, of the thermal coal-fired type, having a unit production cost C_{SE}=19 mills/kWh (running cost = 10 mills/kWh, capital cost 550 $/kW, installed capacity P/0.9). One curve is also indicated for running cost of 20 mills/kWh.

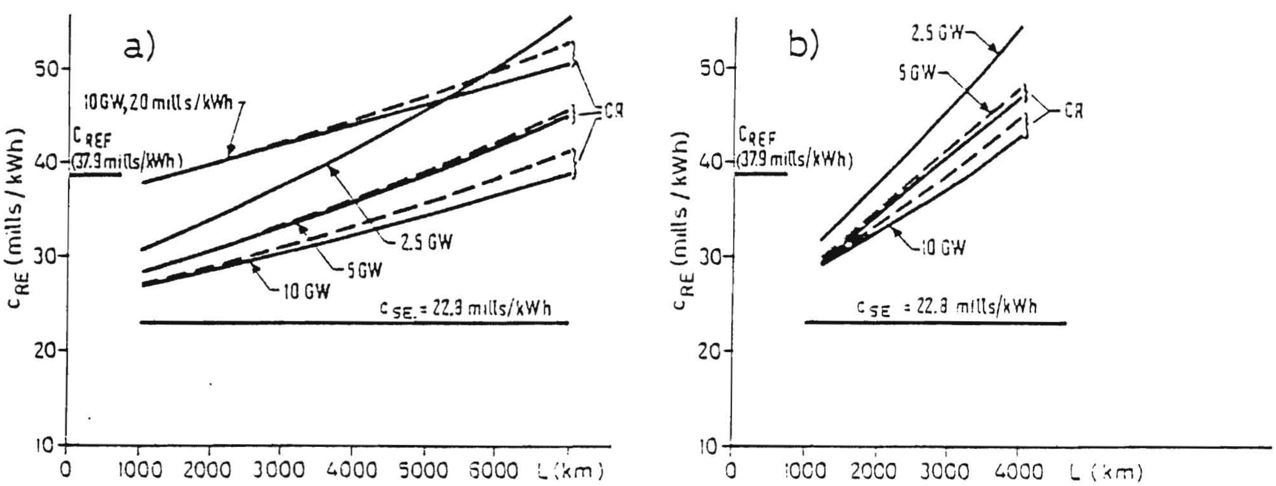

Fig. 5 - Unit cost c_{RE} for D C (a) or A C (b) transmission of P x 5200 GWh/yr from a remote source, of the termal coal-fired type, having a unit production cost C_{SE}=22.8 mills/kWh (running cost = 10 mills/kWh, capital cost 550 $/kW, installed capacity P/0.9). One curve is also indicated for running cost of 20 mills/kWh.

c_R is the risk-cost when reference is made to a system having peak-load of 48 GW

c_{REF} is the unit cost of an alternative production of thermal type located at the receiving system and having a running cost of 25 mills/kWh.

The exhamination of Figs. 3,4 and 5 shows that:

- by increasing L from 1000 to 7000 Km, the transmission cost, for d.c. transmission of 5 GW, varies from ~ 5 mills/kWh to~16 or~22 Mills/kWh for a transmission load factor of 1 or 0.6 respectively.

- by increasing L from 1200 to 2800 km the transmission cost, for a.c. transmission of 5 GW, varies from ~ 5 mills/kWh to 10 mills/kWh (l.f.=1) or to~17 mills/kWh (l.f.=0.6)

- the effect of scale (if risk-cost is not included) is, at least up to 10 GW, considerable: for instance (see fig. 4., L = 3000 Km) the transmission costs vary from 11 to 8 and to 6.5 mills/kWh when increasing the transmitted power from 2.5 to 5 and to 10GW respectively (the unit costs decrease roughly proportionally to $P^{-0.4}$).

6. Cost of Risk

Before proceeding to economic comparisons, one must be sure to compare solutions having similar and acceptable reliability; otherwise, in the case of marked differences, a penalty must by applied to less reliable solutions. On the other hand, it is well-known that the reliability of a transmission link (as evaluated in Section 4) cannot by judged in absolute terms, but must be examined at the light of its consequences for the receiving system: the higher the transmitted power in relation to the size of receiving system, the more important the consequences are.
They may be quantified in terms of the increase in system load-curtailments, due to line outages, compared with an ideal transmission without outage.
Two types of load curtailment were taken into account [8] [9] :

- The yearly expected value of the energy not supplied due to lack of transmission capacity, or "static risk index" (1).

- The yearly expected value of the energy shed due to frequency transients, following a sudden reduction in transmission capacity (e.g. from P to 0), or "dynamic risk index". (2)

The economic penalty due to transmission unavailabilities was quantified by associating a unit cost (in the paper, a value of 2 $/kWh was adopted) with these energy curtailments. The ratio of this penalty to the total energy delivered at the RE represents the risk-cost to be added to the unit cost found in Section 5.

6.1. Reference System

As already mentioned, the higher the percentage of generation connected by the transmission system, the greater the probability of large static or dinamic load-curtailments in the event of transmission outages. Therefore, in order to examine a wide range of these percentages, reference was made to a generating system having a peak load, at RE, of 48 GW (annual energy = 259 TWh) and a reserve margin (remote generation included) of the order of 17.5%. Thus, the three values considered for remote generating capacity (2.5, 5 and 10 GW) roughly represented 4.5, 9, and 18% of total installed capacity.
The system reliability level was-disregarding transmission outages - of the order of 6.10^{-5} (6 kWh not supplied for each 10^5 delivered). The part of the generating system located at the RE had a mix basically of the thermal type.

6.2 Results

The above consideration was confirmed by the results obtained (1): Fig. 6 shows, for example, the increase in expected energy curtailments - due to transmission unavailability. The variation are negligible in the case of transmission capacity equal to 4.5% (2.5 GW), while remarkable increases appear in the cases of 9% (5 GW) and 18% (10 GW).

Fig. 6 also shows that energy curtailments and consequent risk-cost penalties are quite small for the shortest distances - not neglible risk-costs only appear for the more pessimistic assumptions concerning (see 4.1.1) converters unavailability -, but rapidly increase with L.
The cost-of-risk (mills/kWh) for the specific case of a system of 48GW at peak has also been added, in Figs. 3,4 and 5, to the other component costs.
The above results suggest that:

- For the longest distance ($\geq$ 4000 km or $\geq$ 2000 km for d.c. and a.c. transmission respectively) combined with the largest transmission capabilities. ($\geq$ 10% of the total system generating capacity), a solution with three lines (d.c. or a.c.) may be more economical: for instance the 10 GW, 7000 km, 3 bi-poles solution was found to present, always with reference to the 48 GW system, a negligible cost-of-risk and a total specific cost lower than that (cost-of-risk included) of 10 GW with two bi-poles.
This solution might also be more economical when the remote generation system is developed by steps (e.g. two bi-poles for the initial 5 GW, a third bi-poles for up to 10 GW).

- Similarly for the shortest distances (< 2000 km) and the lower transmission capabilities (2,5 GW 5%) a solution with only one bipole is conceivable: it presents acceptable reliability and global specific cost equal to that of the 5 GW with two bi-poles. This solution might also be more economical when the remote generation system is developed by steps.

- In general, for the longest distances combined with transmission capacity representing a large percentage of the receiving system the cost-of-risk reduces the benefits, mentioned at Section 5, of the effect-of-scale.

7. Economic Comparisons

The effectiveness of exploiting remote energy sources may be evaluated by comparing the unit costs (of the electric energy delivered at the RE) with the unit cost of the electricity that might be produced locally. For the latter alternative, thermal power plants were assumed to be connected to the 500kV grid and fired by transported coal (an equivalent running cost of 25 mills/kWh was assumed).

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(1) Use was made of the WAT program [10]

(1) Obviously, an accurate calculation of the dynamic risk-of-failure may be performed only with reference to a specific TR project and receiving system. For purposes of this paper it was assumed that when the sudden loss of transmitted power ΔW_G exceeds 5% of the load W_r (at that moment) an amount of load equal to $1.3\ (\Delta W_G - 0.05\ W_r)$ is shed for a duration of 4 hours (restoration time).

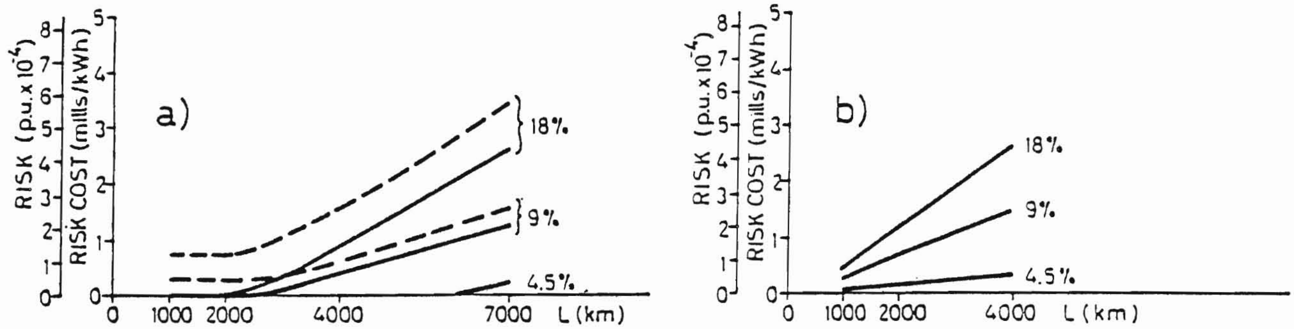

Fig. 6 - Additional energy curtailments (p.u. of the system annual consumption) and corresponding additional risk-cost due to the unavailability of the D C (a) or A C (b) transmission system. The three curves correspond to different percentages of transmission capacity with respect to total system generating capacity (values obtained for 2.5,5,10 GW with respect to a system of 48 GW peak load). (Dotted lines refer to the more pessimistic assumption for d.c. transmission availability described at 4.1.1.).

For a correct comparison of the two unit costs, the two alternatives must offer the same reliability; to this end the alternative local and remote generating sub-systems were associated as specified hereunder.

7.1 Unit cost of Local Generation as compared with Remote Coal

If we adopt the same size for the generating sets, the alternative local generating system has the same installed capacity as the remote one (subtracted, of course, the additional capacity installed at the remote location for supplying transmission losses). More precisely, its capacity is equal to P/0.9 (see Section 5.2).

Therefore, the unit cost of the local generation is equal to:

$$c_{REF} = \frac{550 \times \alpha_{\overline{25}|0.1}}{0.9 \times h_u} + 25 \text{ (mills/kWh)}$$

that is, equal to 34 and 38 mills/kWh for h_u=7400 and 5200 hr/yr respectively.

7.2 Unit cost of Local Generation as compared with Remote Hydro

Since remote hydro generation capacity was characterized as being always available, the equivalent coal-fired local generation must have a much higher installed capacity in order to present the same reliability, namely:

- For hydro with a capacity factor h_u = 5200 hrs/yr, the equivalent (1) coal-fired thermal capacity should be 20% higher, and therefore its cost expressed by

$$c_{REF} = \frac{1.2 \times 550 \times \alpha_{\overline{25}|0.1}}{5200} + 25 \text{(mills/kWh)}$$

is equal to 38 mills/kWh.

- For hydro with a capacity factor h_u = 8760 hrs/yr, the equivalent (1) coal-fired thermal capacity should be 31% higher, and therefore the unit cost is equal to 34 mills/kWh. (2)

8. Conclusions

The exploitation of remote energy sources at low cost (e.g. hydro or mine-mouth, coal-fired plant suitable for producing electricity at a cost of the order of 10 - 25 mills/kWh) is now feasible and economical for distances never before entertained. For example, transmission systems can be set-up over a distance of as much as 7000 km in d.c and 3000-4000km in a.c. such that, by offering an acceptable reliability level for the receiving system concerned, present costs small enough (from 5 to 20 mills/kWh) as to make advantageous the exploitation of those sources, when compared to generation at 30 - 35 mills/kWh located in the vicinity of load centers.

The unit cost of the electric power, transmitted by d.c, shows only small increases when increasing transmission distance: for every additional 1000km the increase is of the order of 1.5 and 2.6 mills/kWh for trasmission of 10 GW and 2.5 GW respectively. By consequence, variations in the cost of energy produced close to consumption centers (as determined by market prices) that may even be smaller than those registered during the past ten years, results in shifts of hundreds (or thousands) of km in the competitive distances of remote sources.

The effect of scale on transmission cost is - at least up to 10 GW - considerable: unit costs decrease approximately proportionally to $P^{-0.4}$.

Although the above-mentioned transmission costs were obtained with reference to transmission schemes with two lines (two bi-poles in the case of d.c), they are nevertheless representative also of the cost of different schemes (see 6.1), since the effect of transmission reliability has been costed and included.

Finally it may be interesting to note that for transmission systems similar to those above described advanced studies are being carried out in Brazil. Those studies, out of which some preliminary information has been here used, confirm the feasibility of the transmission from Amazon region over a distance of about 2500 km, being the implementation foreseen for the mid-nineties, hinging on the growth rate of electricity consumption in the country.

(1) In both cases the "equivalence" was checked with reference to the receiving system (48 GW at peak) considered in Section 6.1. In the first case, a 20% increase is required, to obtain the same risk-of-power (being the energy certainly assured); in the second case (taking into account the overall availability of 0.76 assumed for thermal units) an increase of 31% is required to obtain the same risk-of-energy.

(2) It may be observed that this value is of the same order as the unit cost of nuclear production which was not considered here, for the sake of simplicity.

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