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MARTIN MARIETTA

Comparison of Costs and Benefits for DC and AC Transmission

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POWER SYSTEMS TECHNOLOGY • PROGRAM •

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Energy Division

COMPARISON OF COSTS AND BENEFITS FOR DC AND AC TRANSMISSION

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FOREWORD

The Office of Energy Storage and Distribution of the U.S. Department of Energy has developed a research and development program on high-voltage direct-current (HVDC) power transmission and delivery systems and associated dc components. The program includes analysis of future utility system dc applications, development of dc control and protection techniques, and advanced dc component research. The overall goal of the program is to identify important dc technical options that may be compared with the ac choices when designing or modifying power systems. Specific objectives include development of a fundamental understanding of dc/ac system interactions, determination of bulk power transfer options, investigation of dc power delivery within high load-density areas, and development of dc components and systems. The program is described in *Program Plan for Research and Development of HVDC Power Systems and Components*, DOE/NBB-0065, U.S. Department of Energy, January 1984.

As an important part of this program, a study of the generic cost differences between dc and ac systems was conducted. This report is the result of that study.

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ACKNOWLEDGMENTS

Members of the Task Group met seven times during 1984 and the beginning of 1985 to prepare this report. Other individuals who attended Task Group meetings and provided input were J. J. LaForest, General Electric Company; E. Kolodziej, Central & Southwest Services, Inc.; and Willis F. Long, ASEA, Inc.

The authors also wish to acknowledge the ORNL editors, J. M. Asher and C. W. Hagan, for their work in publishing this document.

ABSTRACT

The purpose of the study reported here was to examine generic cost differences between direct current (dc) and alternating current (ac) systems and to identify situations in which dc is clearly advantageous for long distance and bulk power transport. The study was also designed to determine the value of the dc technology when applied to transmission systems. This report presents cost comparisons between ac and dc substations and transmission lines as a function of capacity and voltage. It also presents a comparison of dc versus ac for increasing the capacity of existing corridors. Direct-current link operating strategies for enhancing the performance of the associated ac network are illustrated. Possible opportunities for simplification and cost reduction of dc converter stations are described. Both current and expected future enhancements for ac system operation are also identified to assist in making comparisons between equivalent systems.

Information is presented to enable comparisons sufficiently detailed to determine "cost break-even distance," which is the transmission length at which the savings in dc line costs (compared to ac) equals the additional cost of the dc converter stations (compared to ac substations). However, it is emphasized that proper use of the concept requires the inclusion of all costs of implementation of those attributes available in the two technologies which are of sufficient value to the power system to be included in determining equivalent systems.

The report attempts to bring together useful cost and performance information on ac and dc power transmission for the use of electric utility system planners in achieving economic and reliable power system designs when considering system additions, expansions, or modifications.

EXECUTIVE SUMMARY

INTRODUCTION

In the last three decades, high-voltage direct-current (HVDC) power transmission has become an important adjunct to conventional alternating-current (ac) power transmission. It is well known that for long-distance overhead and undersea cable, there can be calculated a "break-even distance" beyond which dc is economically advantageous. It is also well known that asynchronous connections between systems can be made using "back-to-back" ac-dc-ac converters, where the break-even distance is zero.

The calculation of a break-even distance is a common early step for utility system planners when comparing ac and dc alternatives. Yet an approximate or "rule-of-thumb" preliminary comparison may be misleading. For evaluation of ac and dc options, the cost and value to the utility of the many attributes of the two technologies should be taken into account.

Since both technical and operational differences exist between the two technologies, care must be taken in making comparisons. First, the system operational requirements must be defined. This allows the inherent capabilities of ac and dc systems to be properly identified so that operationally equivalent ac and dc systems will be compared. That is, economic evaluations should consider systems of equivalent performance, if at all possible. Failure to do so can lead to decisions derived from suboptimal analyses, only to find later, for example, that important but unrecognized system operating requirements must be addressed at additional cost.

Examples of ac or dc power planning and operating strategies that could lead to appreciable total cost reductions are as follows:

- Use of static var control systems to achieve loadings of maximum economy and to provide high-speed control of voltage for stability enhancement in ac transmission.
- Use of series capacitors to reduce system transfer impedance.
- Use of high-speed series capacitor insertion for stability improvement.
- Use of rapid adjustment of transfer impedance for modulation of ac power flows to permit greater dynamically stable loadings.
- Design of dc converter stations and lines for economy loading and minimum electric field effects, plus greater power transfer on a single right-of-way.
- Use of back-to-back asynchronous connections to permit interregional load flow control.
- Modulation of dc power flows to permit greater dynamically stable loadings on parallel ac lines or on contiguous ac systems and to provide rapid assistance between systems.
- Modulation of dc converter reactive absorption to permit assistance to ac voltage control.

- Combined modulation of dc power and reactive absorption for optimum ac assistance and dc efficiency.
- Asynchronous ac-dc-ac connections of generating stations to the ac power system to reduce the cost of the generators and to isolate them from ac system disturbances.
- Improved power system control and protection systems utilizing digital and adaptive techniques.
- Use of high-speed breakers and relaying to reduce the impact of system disturbances on stability.
- Use of momentary energy absorption devices (generator braking resistors).
- Staged or incremental development of dc systems as determined by load growth and the incentive for delaying the expenditure of capital funds.

Table ES.1 lists items that could be examined and evaluated when choosing between the ac and dc options for electric power transmission. The consideration of applicable elements should yield a reasonably comprehensive picture of the total life-cycle cost benefits from either choice and thus permit an informed comparison of the two technologies.

DC SYSTEM CONFIGURATIONS

At present, some 20 North American dc systems are in operation or under construction, and about 10 more are receiving serious planning consideration. Worldwide, the numbers are approximately double those for North America. Direct-current power transmission is flexible in that systems can be constructed in a variety of configurations to meet specific requirements. Further, dc systems can be constructed in stages to conform to increasing load growth.

Direct-current system configurations include the following:

- back-to-back,
- monopolar ground return,
- monopolar metallic return,
- bipolar,
- dual bipolar,
- parallel multiterminal, and
- series multiterminal.

These configurations are briefly described in this report. Each configuration has its own performance and economic aspects that can be optimized. Possible future configurations are also presented.

DC AND AC SYSTEM ATTRIBUTES

Direct-current power transmission systems have a number of attributes that differ from those of ac transmission systems. Their effects may be difficult to quantify, yet they offer the potential for

Table ES.1. Generic cost comparison elements

System cost elements for given power (MW) transmitted and line length	
AC	**DC**
Right-of-way	Right-of-way
Load density per acre of right-of-way	Load density per acre of right-of-way
Transmission voltage	Transmission voltage
Line—Conductors	Line—Conductors
Towers	Towers
Substations or switching stations	HVDC converter stations
Breakers and disconnects	Breakers and disconnects
Transformers	Transformers
Reactive power (capacitive and inductive)	Filters and var supply
Shunt capacitors and reactors	
Series capacitors	
Static var systems	
	Valve assembly and smoothing reactor
	Ground electrode and metallic return transfer breaker
Protection	Protection
Control	Control
Station civil works	Station civil works
Losses—Line	Losses—Line
Station	Station
Communications	Communications
Operating characteristics	Operating characteristics
System reinforcement	System reinforcement
Environmental impact	Environmental impact
Consequences and recovery from	Consequences and recovery from
Short-duration line faults	Short-duration line faults
Long-duration line faults	Long-duration line faults
Stability enhancement	Stability enhancement
Dynamic	Dynamic
Transient	Transient
Recovery from system breakup	Recovery from system breakup
Fault magnitude and breaker interrupting duty	Fault magnitude and breaker interrupting duty
Energy availability	Energy availability
Ease of tapping for intermediate loads	Ease of tapping for intermediate loads
	Conversion of ac lines to dc

substantial cost reductions or improvements in ac system performance. These attributes need to be reflected in the cost of a dc system when compared with the costs of alternatives; they include

- dc power modulation,
- limitation of fault current,
- asynchronous interconnections (back-to-back and long distance),
- variable-frequency operation,
- control of circulating currents in contiguous networks,
- system operation restoration,
- upgrading power corridor capacity,
- staged construction, and
- dc system reliability.

Alternating-current systems likewise have attributes that can offer the potential for cost reductions or improvements in system performance. These include

- ac power modulation,
- limitation of fault current,
- facility of network operation,
- intermediate tapping,
- out-of-step protection and controlled islanding,
- system operation restoration,
- staged construction, and
- ac system reliability.

Fast controllability of a dc link and rapid control of ac transfer impedance enable a response to ac system dynamics that can minimize consequences of system disturbances.

In the event of an ac system fault, a dc inverter will not contribute to the fault current. In response to the distorted ac voltages, the inverter will fail commutation, effectively removing its current from the fault. Alternating-current system fault current near a rectifier is likewise limited. Provided that some commutation voltage exists, the rectifier attempts to draw real and reactive power away from the fault.

The asynchronous nature of an ac-dc-ac back-to-back converter enables interconnections that would otherwise be difficult or impossible to achieve. Interregional and international energy exchanges are made possible by this mode of operation of dc links. Long-distance transport of Canadian hydropower to U.S. load centers can also be anticipated.

The unit rectifier-generator system is discussed in regard to reductions in dc system costs. Since the generators in the unit system operate asynchronously, it is possible to envisage generation at frequencies that may be higher than conventional, thereby reducing the size and costs of the generators, transformers, and associated switchgear. Variations in generator winding design may be possible so as to operate without ac filters. Generator output voltage need not be a pure sinusoid (assuming no local load). Fault currents, being derived from a single unit, will be much smaller than are typically expected.

The asynchronous nature and controllability of dc can aid in restoration following major system breakups. If the ac system collapses following a severe disturbance, the receiving system could be subdivided to allow the ac network near an inverter to recover quickly. This would give a base on which to rebuild the rest of the system.

An existing ac line that was converted to dc would have its transmission capacity increased, typically by a factor of 2 to 3.

CONCLUSIONS

This report presents information intended to assist electric utility system planners in making economic comparisons between equivalent ac and dc transmission systems. In doing so, it sets forth operational characteristics of the two systems, including

- controllability of ac and dc systems,
- asynchronous interconnection using dc,
- power flow modulation by ac and dc systems,
- ac voltage control by ac and dc systems,
- power routing by ac and dc system controls,
- increased power density over a transmission corridor by using dc,
- unchanged ac power flows and short-circuit levels by using dc,
- control of short circuit impact by using ac techniques, and
- reduced environmental impact in a dc line as compared with an ac line.

For ac systems, information is provided on the use of series and shunt compensation to increase power transmission while retaining stability and acceptable voltage profiles. Examples of sample calculations are provided, together with curves for comparing alternatives.

Data are provided for use in calculating dc converter station costs as a function of power, dc voltage, and ac voltage. Cost data for ac substations, dc and ac transmission lines, and dc underground cables are also presented. Techniques for calculating total costs (including the capitalized costs of losses) are included.

This report also presents some not-yet-implemented concepts for dc transmission for consideration, with the exception that a future application may be found. Significant future economic benefits could accrue from these concepts.

Finally, there are probably too many variables and too many constraints to be able to design an "optimum" system. However, if the aim of the system planner is to achieve an economic and reliable design, then the information contained in this report for both dc and ac systems may be of value.

1. INTRODUCTION

In the last three decades, high-voltage direct-current (HVDC) power transmission has become an important adjunct to conventional alternating-current (ac) power transmission. It is well known that for long-distance overhead and undersea cable transmission there can be calculated a "break-even distance" beyond which dc is economically advantageous. It is also well known that asynchronous connections between systems can be made using "back-to-back" ac-dc-ac converters, where the break-even distance is zero.

The calculation of a break-even distance is a common early step for utility system planners when comparing ac and dc alternatives. Yet an approximate or "rule-of-thumb" preliminary comparison may be misleading. For evaluations of ac and dc options, the cost and value to the utility of the many attributes of the two technologies should be considered.

Consider the following situation. As a result of minimal construction of new generating facilities, utilities will come under increasing pressure during the next ten years to use their existing transmission systems more efficiently. The opportunity to wheel power from regions of surplus to regions of deficiency can be economically advantageous and will improve overall system reliability. Direct-current power transmission can play a key role in the scenario; however, it must be compared against a truly equivalent ac alternative.

The purpose of this study was to examine generic cost differences between dc and ac systems and to identify situations in which dc is clearly advantageous for long distance and bulk power transport. The study was also conducted to determine the value of the dc technology when applied to transmission systems. This report presents cost comparisons between ac and dc substations and transmission lines as a function of capacity and voltage. It also presents a comparison of dc versus ac for increasing the capacity of existing corridors. Direct-current link operating strategies for enhancing the performance of the associated ac network are illustrated. Possible opportunities for simplification and cost reduction of dc converter stations are described. Current and expected future enhancements for ac system operation are also identified to assist in making comparisons between equivalent systems.

Since there are both technical and operational differences between the two technologies, care must be taken in making comparisons. First, the system operational requirements must be defined. This allows the inherent capabilities of ac and dc systems to be properly identified so that operationally equivalent ac and dc systems will be compared. That is, economic evaluations should consider systems of equivalent performance, if at all possible. Failure to do so can lead to decisions derived from suboptimal analyses, only to find later, for example, that important but unrecognized system operating requirements must be addressed at additional cost. Such considerations would have been important to the earlier decision had they been recognized. However, some features do not lend themselves to ready or easy comparative evaluations. For example, to achieve the same performance as a relatively small interregional back-to-back dc link might require a long-distance high-capacity ac intertie.

Examples of ac or dc power planning and operating strategies that could lead to appreciable total cost reductions are as follows:

- Use of static var control systems to achieve loadings of maximum economy and to provide high-speed control of voltage for stability enhancement in ac transmission.
- Use of series capacitors to reduce system transfer impedance.
- Use of high-speed series capacitor insertion for stability improvement.
- Use of rapid adjustment of transfer impedance for modulation of ac power flows to permit greater dynamically stable loadings.
- Design of dc converter stations and lines for economy loading and minimal electric field effects, plus greater power transfer on a single right-of-way.
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- Improved power system control and protection systems utilizing digital and adaptive techniques.
- Use of high-speed breakers and relaying to reduce impact of system disturbances on stability.
- Use of momentary energy absorption devices (generator braking resistors).
- Staged or incremental development of dc systems as determined by load growth and the incentive for delaying the expenditure of capital funds.

The technical characteristics of dc power transmission have been well documented and thus will not be addressed in this report. For a detailed description of dc planning considerations, see the report, *Methodology for Integration of HVDC Links in Large AC Systems—Phase 1: Reference Manual*, EL-3004, Electric Power Research Institute, Palo Alto, California, March 1983.

Table 1.1 lists items that could be examined and evaluated when choosing between the ac and dc options for electric power transmission. The consideration of applicable elements should yield a reasonably comprehensive picture of the total life-cycle cost-benefits from either choice and thus should permit an informed comparison of the two technologies.

Table 1.1. Generic cost comparison elements

System cost elements for given power (MW) transmitted and line length	
AC	DC
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	Valve assembly and smoothing reactor
	Ground electrode and metallic return transfer breaker
Protection	Protection
Control	Control
Station civil works	Station civil works
Losses—Line	Losses—Line
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Communications	Communications
Operating characteristics	Operating characteristics
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Long-duration line faults	Long-duration line faults
Stability enhancement	Stability enhancement
Dynamic	Dynamic
Transient	Transient
Recovery from system breakup	Recovery from system breakup
Fault magnitude and breaker interrupting duty	Fault magnitude and breaker interrupting duty
Energy availability	Energy availability
Ease of tapping for intermediate loads	Ease of tapping for intermediate loads
	Conversion of ac lines to dc

Part I

PLANNING CONSIDERATIONS AFFECTING TRANSMISSION SYSTEM COSTS

2. DC SYSTEM CONFIGURATIONS

At present, some 20 North American dc systems are in operation or under construction, and about 10 more are receiving serious planning consideration.[1] Worldwide, the numbers are approximately double those indicated for North America Direct-current power transmission is flexible in that systems can be constructed in a variety of configurations to meet specific requirements. Further, dc systems can be constructed in stages to conform to increasing load growth.

Direct-current system configurations include the following:

- back-to-back,
- monopolar earth return,
- monopolar metallic return,
- bipolar,
- dual bipolar,
- parallel multiterminal, and
- series multiterminal.

These configurations will be briefly described in this chapter; more detailed information is available in the literature.[2-4] Each configuration has its own performance and economic aspects that can be optimized. Possible future configurations are presented in Chap. 6 of this report.

2.1 BACK-TO-BACK LINK

The configuration of the back-to-back link is shown in Fig. 2.1. Two converters are connected by a smoothing reactor and serve as an asynchronous tie between the two ac systems. Only one

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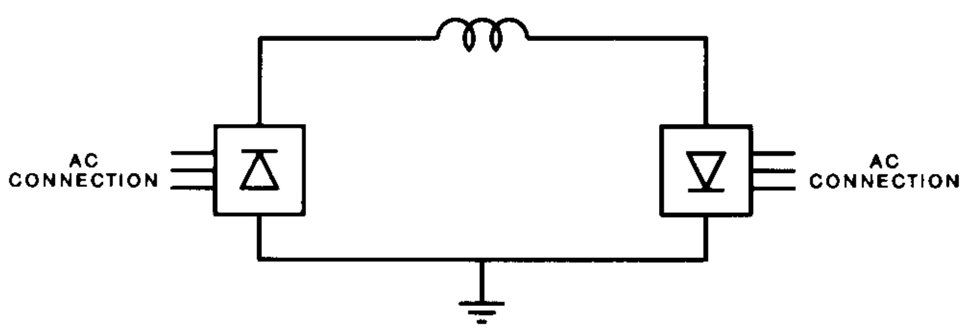

Fig. 2.1. Back-to-back dc link.

ground connection is required. The two converters are usually housed in a single structure. The reactor, which can be a small air-core device, is generally outdoors.

As an asynchronous tie, this scheme can enable power exchanges between two systems that cannot be synchronized. This technique has been used along the boundary of the eastern/western U.S. systems, near the U.S.–Canadian border in the Northeast, between Texas and adjacent states, between eastern and western Europe, and in several 50-Hz–60-Hz interconnections. The economic design of components in a back-to-back system results in converters operating at relatively low dc voltage and high dc current. For example, the Chateauguay, Quebec, back-to-back link operates with a nominal dc pole voltage of 140 kV and pole current of 3600 A for a pole power of 500 MW. In comparison, the New England to Quebec interconnection, which includes 171 km (107 miles) of overhead line, will operate at 450 kV, 766 A, and 345 MW per pole.

The use of a transmission line or cable has a very dramatic influence on converter ratings, and it can be seen that the optimum choice of parameters will change from system to system.

2.2 MONOPOLAR GROUND RETURN

The monopolar ground return configuration is shown in Fig. 2.2. As its name implies, one conductor is energized (one pole), and the return current path is through the ground. The earliest dc systems were of this type, with submarine cables and sea electrodes for the return current. The principal concerns with this configuration are related to the electrodes. They must carry the link current at all times; corrosion, harmonic current, and other protection matters must receive careful attention.

This configuration may serve as a backup mode of operation for the more common bipolar systems (Sect. 2.4). In the event of a pole outage (conductor or converter bridge), it is possible to transmit half the rated power over the remaining pole plus the ground path. (More than 50% of the rated power may be transmitted if converter overload capability has been designed into the system.) The electrodes must carry the pole current. A ground-return-current ampere-hour per year restriction may be imposed to limit operation in this mode. Ground return operation may not be feasible in urban regions because of the high probability of interference with many other underground metallic structures and facilities.

2.3 MONOPOLAR METALLIC RETURN

The monopolar metallic return configuration is shown in Fig. 2.3. Return current flows through a conductor, rather than through the earth, thus avoiding the interference and corrosion problems

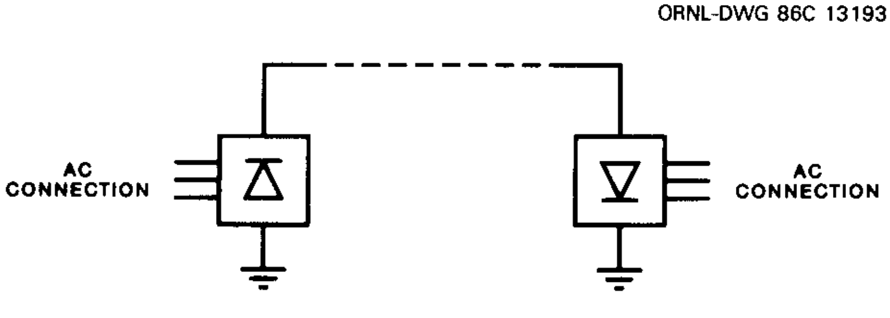

Fig. 2.2. Monopolar ground return.

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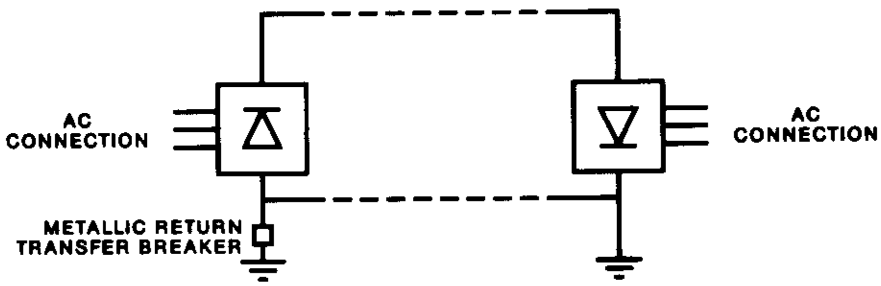

Fig. 2.3. Monopolar metallic return.

mentioned previously. The metallic return mode is the principal contingency mode of operation for a bipolar system with a converter outage on one pole. The converter and its counterpart at the other end of the system are bypassed, providing a line conductor and a neutral conductor for return current.

To divert the current out of the ground path (a lower resistance path) into the return conductor requires a metallic return transfer breaker (MRTB) in one ground connection. Opening this device (a low-voltage dc circuit breaker) creates a countervoltage in excess of the line drop, transferring the current. Since the converter nearest the MRTB is no longer grounded, a capacitor/surge arrester combination will be required for the neutral bus for overvoltage protection.

This backup system can transmit half the power of a bipolar system (discounting overload), but the percentage line losses will be twice as high. There would be no ampere-hour restriction since there is no ground current.

2.4 BIPOLAR SYSTEM

The bipolar configuration (Fig. 2.4) is the commonly used arrangement for dc systems employing overhead lines and, more recently, cables as well. In this configuration there are two poles, with one or more converters per pole, at each terminal. There are two conductors, one per pole, generally of equal voltage (but opposite polarity). The midpoints between the converters at each end are grounded. If the conductor currents are equal, there will be no ground current.

Earlier systems employing mercury arc valves were limited in bridge voltage to 150 kV or less. Thus, to achieve optimal line voltages in the range of 400–500 kV, it was necessary to series connect valve groups. A group outage (whether equipment failure or maintenance) caused a power reduction, but the same current could still be maintained in both poles. However, ac harmonic currents would be affected.

Thyristor valves have been constructed up to a dc voltage of 500 kV, so future systems up to that voltage level can be expected to employ one valve group (three quadrivalves) per pole.

Lightning-induced bipolar outages are not known to occur since the lightning polarity will cause a flashover to only one pole. An argument can be made that a bipolar dc system is thus equivalent to a double-circuit ac system (on one set of towers). To be "equivalent," the two systems would have to have equivalent availabilities. However, since the two systems would function quite differently, the equivalence becomes difficult to quantify. This is an issue best left to reliability councils to debate.

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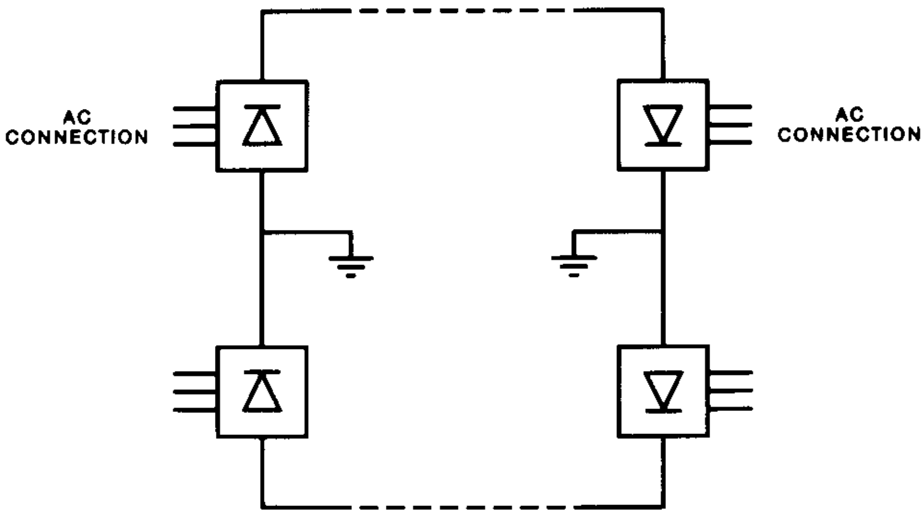

Fig. 2.4. Bipolar system.

2.5 DUAL BIPOLAR SYSTEM

A dual bipolar system is a doubling of the bipolar system shown in Fig. 2.4. Two transmission lines are constructed, and switching facilities enable the paralleling of converters onto one conductor in the event of a fault on the other of like polarity. Similarly, if a tower is lost, converters on both poles can be paralleled. Line losses are increased, but transmission capacity is maintained. Dual bipole configurations are appropriate only for the largest dc systems and will generally evolve through staged construction.

2.6 MULTITERMINAL SYSTEMS

There are two basic multiterminal network configurations in which dc converters can be connected for parallel or series operation. These are shown in Figs. 2.5 and 2.6 as a monopolar system.

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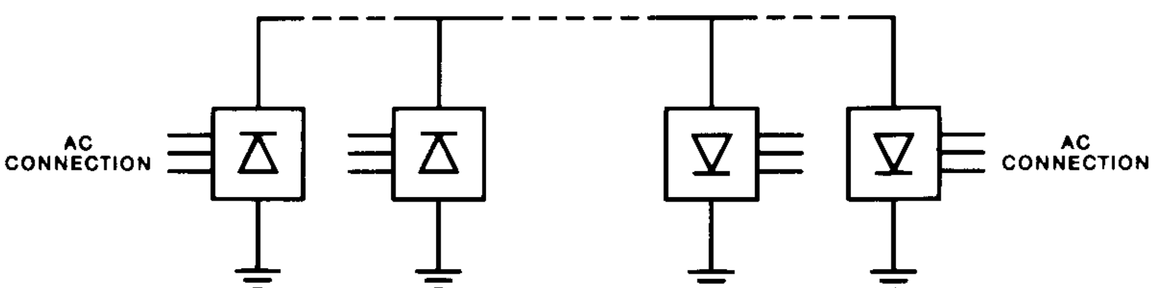

Fig. 2.5. Parallel multiterminal system.

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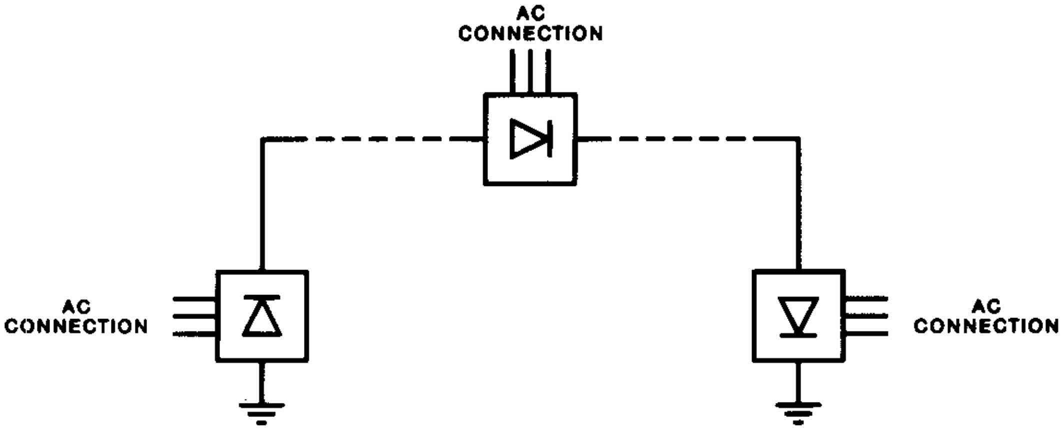

Fig. 2.6. Series multiterminal system.

2.6.1 Parallel Operation

A parallel-connected dc network has only one system voltage. Thus one converter determines the operating voltage, while all other converters operate in a current-controlling mode. The converter having the minimum voltage capability is typically chosen for the voltage-controlling function. If it is an inverter, it will operate in a margin angle control mode with a negative backup current margin. If it is a rectifier, it will operate in a minimum firing-angle mode with a positive backup current margin.

If the voltage-controlling station is an inverter, it may be vulnerable to overloading (excess current) in the event of system disturbances, major load changes, etc. This would be especially true of a small inverter, where commutation failures can lead to very large overcurrents. Having the system voltage determined by a rectifier may result in more stable operation since each inverter can increase its back voltage to limit current. Since the voltage-controlling rectifier has a (positive) current margin, it is not vulnerable to overloading.

The parallel connection of converters can suffer from a number of drawbacks, including the following:

- A dc-side disturbance (e.g., line fault or commutation failure) affects the whole system.
- Loss of a line can result in the loss of a large proportion of the system unless a meshed network configuration is used.
- Reversal of power at any station requires mechanical switching.
- Loss or removal of one pole converter in a bipolar system results in ground current and may necessitate a neutral conductor.

A centralized control system providing current allocation and a fast, reliable communication system will be important features of a parallel multiterminal system. In the event of the loss of one or both of the above, the system can be designed to respond to disturbances by transferring to an interim operating point at partial power.[5] Direct-current circuit breakers can also add to the flexibility of parallel multiterminal systems through the rapid removal of a faulted converter or line segment.[6,7]

2.6.2 Series Operation

In earlier dc systems, converter bridges were connected in series to achieve optimum pole voltage for efficient transmission. The extension of this concept to series multiterminal systems is straightforward.

It is seen in Fig. 2.6 that there is one current in a series system, determined by one converter. All other converters operate against firing-angle limits and can be either rectifiers or inverters. Converters can easily be added or removed, and power can be quickly reversed. In general, this configuration is less vulnerable to disturbances. Direct-current circuit breakers are not needed.

Independent power control is achieved at each terminal without a requirement for high-speed central load dispatch control. Power variations at any terminal are automatically compensated at the current-controlling terminal. Communication between terminals is required for optimization of line loadings to minimize losses (i.e., if all terminals are lightly loaded, the line current can be reduced accordingly), but this does not require high-speed information transfer.

The drawbacks of series operation are as follows:

- A midpoint station (as in Fig. 2.6) is at pole potential and thus must be fully insulated to ground.
- Reactive power requirements are high since a wide range of firing angles will be necessary for voltage control.
- Efficiency is reduced because the full line voltage insulation is not used and also because the increased firing-angle range will lead to higher losses.

2.6.3 Economic Considerations

For a tapping station rated less than 20% of the system rating, it is expected that the series system will be favored. In a parallel system a neutral conductor may be required to eliminate ground currents with one converter out of service. The cost of a parallel converter tap is more than proportional to its rating[4] since it will have less than full system current but will have full system voltage. Direct-current circuit breakers will add flexibility, probably at a cost that is not significant in comparison with the overall system cost.

Multiterminal systems can be considered for system expansions.[4] Both economics and operating modes will need to be examined carefully and may be quite different from the case when a multiterminal system is planned from the beginning of a system design.

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3. TRANSMISSION SYSTEM ATTRIBUTES

Direct-current power transmission systems have a number of attributes that differ from those of ac transmission systems.[1] The costs of these attributes in both ac and dc systems may be difficult to quantify in all cases. However, many of these attributes offer the potential for either substantial cost reductions or performance improvements, or both. Those attributes that have sufficient value should be selected, and their costs should be reflected in the cost estimates of the ac and dc systems under study when comparing the total costs of the two alternatives.

Direct-current system attributes, some of which may impose additional costs over those of a straightaway energy transport system, include

- dc power modulation,
- limitation of fault current,
- asynchronous interconnections (back-to-back and long distance),
- variable-frequency operation,
- control of circulating currents in contiguous networks,
- system operation restoration,
- upgrading of power corridor capacity,
- staged construction, and
- dc system reliability.

Alternating-current system attributes, many of which may impose substantial costs, include

- ac power modulation,
- limitation of fault current,
- facility of network operation,
- intermediate tapping,
- out-of-step protection and controlled islanding,
- system operation restoration,
- staged construction, and
- ac system reliability

3.1 AC AND DC POWER MODULATION

In ac system operations, currently available and potential mechanisms and techniques for improving transient stability and for damping machine oscillations include

- thyristor- and breaker-switched shunt capacitors,
- thyristor-controlled shunt reactors,
- breaker-switched shunt reactors,
- switched and modulated series inductive or capacitive compensators,

- rapid adjustment (thyristor) of transfer impedance,
- modulated phase shifters,
- generator and synchronous compensator supplemental excitation control,
- momentary energy absorption devices (generator braking resistors),
- embedded microprocessor controls,
- out-of-step protection and system islanding,
- traveling wave relaying,
- single pole relaying and fault clearing,
- automatic reclosing, and
- load shedding and generator dropping.

Power modulation for the purpose of improving transient and dynamic stability may be implemented in the ac technology by means of rapid adjustment of transfer impedance. Similarly, the fast controllability of a dc link can be used to respond to ac system dynamics to minimize unwanted disturbances.

Through firing angle control of rectifier and inverter voltages, dc can be modulated in response to an error signal derived from the disturbance. The modulation must be programmed so that the current margin is preserved at all times. Thus a stable operating point is maintained about which the modulation occurs. In cases of large signal modulation, it may be necessary to temporarily increase the margin or to have a fast communication link. Reactive power voltage support may need to be increased as well for the ac system.

An early application of improved ac system performance through low-level modulation was developed for the Pacific HVDC Intertie.[2] Interarea dynamic oscillations limited the transfer capability of the two parallel 500-kV ac intertie lines. Direct-current modulation of 3% was effective in counteracting this oscillation and was a significant consideration when an increase in ac intertie capacity of 400 MW (about 20%) was achieved. Other experiences with power modulation and other dynamic control features are described in the literature.[3]

Two caveats are offered. First, if current in excess of the converter rating is desired, it will be necessary to design this overload capability into the converter valves and transformers. This will influence the cooling system's capabilities and overall converter cost. Second, increased dc causes increased reactive power consumption, creating a drop in ac system voltage. In a strong ac system, this may be of little consequence, but in a weak (high-impedance) system, the voltage drop may be severe enough to limit operation without the addition of reactive power supplies such as static var systems or synchronous compensators. Advanced control techniques or operating strategies may assist in minimizing the system interactions.

3.2 LIMITATION OF FAULT CURRENT

In the event of an ac system fault, a dc inverter will not contribute to the fault current. In response to the distorted ac voltages, the inverter will fail commutation, effectively removing its current from the fault. Alternating-current system fault current near a rectifier is likewise limited. Provided that some commutation voltage exists, the rectifier attempts to draw real and reactive power away from the fault. The action may be complicated to some extent by low-voltage current limits, which may reduce the dc line current and therefore the ac-side converter currents.

It can therefore be seen that existing systems can be reinforced by dc without the requirements to replace or upgrade existing equipment (i.e., switchgear and transformers) which might otherwise be overstressed during faults. Inverter terminals injecting power at intermediate ac voltage levels may be attractive since the inverter terminal does not add extra fault clearing duties to the existing system equipment. It may also be effective to distribute several infeeds throughout the receiving system, sited at strategic points (i.e., multiterminal operation) to avoid ac system impedance limitations.[4,5]

The addition of a new ac line will generally increase the fault magnitudes for maximum faults near the new line's terminals. Nevertheless, high-speed relaying and circuit breakers, usually in bus-sectionalizing positions, can be operated rapidly enough to safeguard other breakers before they are called on to interrupt the maximum faults which might have been beyond their interrupting ratings. This would obviate the need to replace overdutied circuit breakers because of the fault contributions from a new ac line.

3.3 ASYNCHRONOUS INTERCONNECTIONS

The asynchronous nature of an ac-dc-ac back-to-back converter enables interconnections that would otherwise be difficult or impossible to achieve (see Sect. 2.1). Interregional and international energy exchanges are made possible by this mode of operation of dc links.[6] Long-distance transport of Canadian hydropower to U.S. load centers can also be envisioned.

3.4 VARIABLE-FREQUENCY GENERATION

The unit rectifier-generator system is discussed in Sect. 6.2 regarding reductions in dc system costs. However, some possibilities for cost reductions on the ac system side include

- reduction in cost of generators and associated equipment,
- conservation of energy resources, and
- system damping.

3.4.1 Potential Reduction in Cost of Generators and Associated Equipment

Since the generators in the unit system operate asynchronously, it is possible to envisage generation at frequencies that may be higher than conventional ones, thereby reducing the size and costs of the generators, transformers, and associated switchgear. Variations in generator winding design may be possible so as to operate without ac filters. Generator output voltage need not be a pure sinusoid (assuming no local load). Fault currents, being derived from a single unit, will be much smaller than are typically expected.

3.4.2 Conservation of Energy Resources

Another aspect of the flexibility of the frequency of generation is that, at loads other than the rated load of the generator and turbine, the generation frequency could be adjusted to give the maximum efficiency of generation. This could be particularly useful in a hydroelectric facility.

In a conventional system, the turbine-generator is designed for maximum efficiency at a fixed frequency and a given load. At other loads the efficiency drops and energy is lost. A capability to match the generation frequency to the optimum flow rate in the turbine could improve the efficiency of the turbine at loads other than the rated load.

3.4.3 System Damping

A tolerance to frequency variations also means that the mechanical energy stored in the generator/turbine rotors can be used by modulating the dc system controls to damp oscillations in the receiving system, to stabilize parallel ac lines, or to damp tie-line oscillations.

3.5 RESTORATION IMPROVEMENT

The asynchronous nature and controllability of dc can aid in the restoration following major system breakups. If the ac system collapses following a severe disturbance, the receiving system could be subdivided to allow the ac network near an inverter to recover quickly. This would give a base on which to rebuild the rest of the system.

Given a multiterminal system with several inverters, the ac system could be rebuilt simultaneously in different areas (i.e., islanding). The various islands would be synchronized for reconnection using the controllability of the dc to adjust frequency and phase relationships of the separate sections. This approach could speed the recovery of the system considerably and would be amenable to automatic recovery techniques.

On ac systems, techniques of out-of-step protection, load shedding, generator dropping, and controlled islanding are well developed and have been implemented widely. These should also lend themselves well to the application of automatic recovery techniques.

3.6 UPGRADING OF POWER CORRIDOR CAPACITY

An existing ac line that was converted to dc would have its transmission capacity increased, typically by a factor of 2 to 3 (ref. 7). If two such lines were converted, they could be reconfigured as three bipoles. Techniques now exist to operate such bipoles in parallel to give an extremely secure system. Therefore, it is conceivable to convert certain existing ac lines to dc to increase power transfer capabilities, while at the same time increasing the security of the system.

3.7 STAGED CONSTRUCTION

Direct-current power transmission systems can be built and operated in stages; this is commonly done now for larger systems. (In a bipolar system, as previously mentioned, the two poles need not operate at the same voltage. The pole currents will be controlled to be equal.) This provides the capability of matching generation, transmission, and load requirements and can thereby reduce financing costs.[8]

3.8 DC SYSTEM RELIABILITY

The availability of a dc system for the transmission of power is affected by operating modes that enable partial transmission under contingency conditions. Several examples are as follows:

- If one conductor of a bipolar system is out, operation can continue in a monopolar mode.
- If one converter of a bipolar system is out, operation can continue in a monopolar metallic return mode.

- If one converter is out in a system with series-connected converters on each pole, operation can continue at reduced voltage.
- If one converter is out in a system with parallel-connected converters on each pole, operation can continue at reduced current.
- If there are repetitively occurring flashovers caused by pollution, the dc system can (if so designed) be operated at reduced voltage.
- If one pole of a bipolar system is lost, the other pole can (if so designed) be operated at a significant overload.

The reliability performance of dc systems throughout the world has been reported regularly since 1968 by a working group of CIGRE Study Committee 14, DC Links.[9,10] Annual reports on reliability performance are submitted to the working group by utilities with operating dc systems. The key indicators of performance are energy availability and energy utilization. Energy availability is a measure of the energy that could have been transmitted by the dc system except for limitations due to equipment outages, whether forced or scheduled. (Energy unavailability is 1 − energy availability). Energy utilization is a measure of the energy actually transmitted over the dc system and is affected by operating conditions (e.g., low water flows).

The CIGRE reports itemize outages by system and by equipment category. They do not, however, provide information on operating and/or maintenance philosophies that can affect performance data. For instance, Nelson River has had more transmission capacity than generation capacity, in effect, having a "spare pole." Immediate repair and maintenance thus become less of a consideration. Similarly, line and cable outages can have a negative influence on energy availability or utilization, yet they are not a measure of converter performance. It is important to note that the CIGRE reports are of significant value but must be correctly interpreted. Direct comparisons between the reliability of dc and ac systems are not possible.

Perhaps a more useful way to summarize industry data would be to tabulate the average annual energy unavailability of each operating system for all years reported and then comment on factors that affect performance. Table 3.1 gives the average annual unavailability for thyristor valve systems through 1982.

With these specific results by system, it is possible to elaborate on reasons for variations. For example, Hokkaido-Honshu and Shin-Shinano have very low utilization factors (about 5%). This results in very limited exposure to forced outages and also in minimum need for scheduled maintenance. Cabora Bassa also had low utilization in 1980–1982; however, only one terminal of Cabora Bassa is covered by the CIGRE reports. Nelson River Bipole 2 does not have spare converter transformers and therefore had very high unavailability in one year because of transformer outages. Both CU Project and Vancouver Pole 2 had extended periods of low system demand, resulting in planned outages of longer than normal duration.

If the systems discussed in the preceding paragraph are omitted, the range of average annual energy unavailability is 2.43 to 5.70%. If Viborg (a Finland–Russia asynchronous tie) is also excluded, since it has only one year of data and is not manufactured by a major supplier in North America, the range is 2.43 to 3.76% for the Square Butte, Eel River, David Hamil, and Skagerrak systems. The average energy unavailability for these four systems is 2.8%, including both scheduled and forced outages. In 1983–84 these systems had an average scheduled energy unavailability of 2.10% and an average forced energy unavailability of 0.45%.

Table 3.1. Average annual unavailability for thyristor valve systems through 1982

Rank	System	Energy unavailability (%)	Years reported
1	Hokkaido-Honshu	1.25	4
2	Shin-Shinano	1.80	5
3	Cabora Bassa	2.35	6
4	Square Butte	2.43	6
5	Eel River	2.51	11
6	David Hamil	2.53	6
7	Skagerrak	3.76	7
8	Viborg	5.70	1
9	Vancouver Pole 2	6.63	6
10	CU Project	8.63	3
11	Nelson River Bipole 2	11.56	5
	Total		60

The reliability of dc systems can be expected to continue to improve through the use of the self-protecting thyristors, zinc oxide arresters, redundant control and protection systems, redundant cooling and auxiliary electrical systems, improved operator training, and better systems analysis tools.

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4. TRANSMISSION SYSTEM CONSIDERATIONS

Recent trends in the electric utility industry have produced increased interest in the bulk transmission of power from areas with an excess of low-cost generation capacity to areas where generation is expensive or capacity is deficient. When the opportunity for such power interchange is identified, it is often economically advantageous to exploit these transactions with the least delay. Unfortunately, transmission capacity is often not available to convey this power, and transmission additions must be made. When evaluating dc as one of the transmission options, it is necessary to examine right-of-way (ROW), environmental, and overhead line and cable conversion considerations.

4.1 OVERHEAD TRANSMISSION: RIGHT-OF-WAY AND ENVIRONMENTAL EFFECTS

Any comparison of dc and ac transmission systems requires an evaluation of different design criteria and the effects of these criteria on the cost of the systems under study.[1–3] One major difference between ac and dc transmission systems is the reduced ROW requirement of dc overhead lines. Since dc systems use two poles, rather than the three phases of an ac system, less ROW width is needed for dc overhead lines. It is possible to reduce the ac ROW width by using a delta configuration. However, this reduction comes at the expense of increased height, which increases the cost of the transmission towers and the visual impact of the line.

Similarly, the use of dc lines in a vertical configuration requires less height than for ac systems. The design height is determined by a complex analysis of many factors, such as maximum electric field strength, field strength at the edge of the ROW, strength and weight of conductors, span length, National Electric Safety Code (NESC) clearances, and thermal rating and its effect on conductor sag.

Conductor sizes are usually not a direct function of the thermal rating of the line. Environmental factors such as maximum electric fields, television interference (TVI), radio interference (RI), and audible noise determine the conductor size and the number of conductors in a bundle. All of these criteria are site specific; consequently, it is not possible to specify general design criteria. Local regulations as well as local environmental factors must be included in any evaluation.

Estimates of typical ROW widths are difficult to make with any confidence since the range can vary widely. Many factors must be considered. For example, electric fields (particularly at the edge of the ROW), audible noise, RI, NESC clearances, and space charge (in the case of dc) must be considered in defining the ROW width. These factors are a function of numerous design values such as operating voltage, span length, phase or pole spacing, conductor height, conductor diameter, bundle diameter, and number of conductors per bundle. In addition to the above factors, dc line design must also include the possible effects of dc space charge and ion drift, which are presently being studied in an attempt to further understand these phenomena.

Typical maximum electric field strengths under ac transmission lines range from 3.0 to 12 kV/m. The values at the edge of the ROW are typically 1.6 to 2.0 kV/m. Typical ROW widths for ac lines are 46 m (150 ft) for 230 kV and 61 m (200 ft) for 500 kV. Values for dc lines are as follows: 23 m (75 ft) for a ±250-kV line with a 183-m (600-ft) span length, 35 m (115 ft) for a ±250-kV line with a 305-m (1000-ft) span length, and 43 m (140 ft) for a ±400-kV line. These values can vary widely depending on line designs and local conditions.[4]

Other environmental effects are also created by dc converters. Harmonics on both the ac and dc side of the converter must be considered. Not only are their effects on the ac power system of interest, but also their possible effects on adjacent communication systems. (These can be mitigated with proper filter designs.)

In some areas of the country, it may be necessary to use a neutral conductor with a dc system to eliminate the effects of ground return currents on underground pipelines and railway signals. In areas where it is possible to use the earth as a ground return, the design and siting of the ground electrode must be given careful consideration.

The power transmitted on an existing ac ROW can usually be increased by converting the line to dc. Hybrid ac and dc lines can coexist on the same ROW and possibly on the same tower structures. Coupling between systems, reliability, and all the previously discussed environmental effects must be given consideration. The design constraints of many applications may not be favorable to a hybrid use of an ROW. However, in certain site-specific designs the use of ac and dc lines on a single ROW could prove to be economically and environmentally acceptable.[5]

4.2 UNDERGROUND TRANSMISSION: RIGHT-OF-WAY AND ENVIRONMENTAL EFFECTS

The ROW requirements for ac and dc underground systems are essentially equal. Mechanical design criteria are identical for both systems since the requirements for installation and access for maintenance and repairing are the same. The primary criterion for the selection of spacing between cables is thermal interference. Since similar insulation materials are used and the mechanism of heat dissipation is identical (regardless of operating voltage), the spacing between cables is identical. If a neutral conductor is used, which would be typical of an installation in an urban environment, then the dc system would require the same number of conductors as an ac system. It is important that the rating of the dc neutral conductor receive the same attention as that of the pole conductors. The thermal rating of the neutral conductor and the remaining pole conductor during contingency conditions will determine the rating of the circuit.

The electrical losses of dc underground cables are less than those of ac cables because there are minimal dielectric losses and there are no skin or proximity effects in dc cables. Hence, ratings for dc cables are typically higher than for ac cables of the same size. For example, a 2500-kcmil 220-kV ac high-pressure oil-filled pipe-type cable has a rating of 450 MVA. A 600-kV dc cable would require a similar insulation wall but would have a rating of ~1000 MVA when installed in an area with the same thermal conditions. Sheath losses in ac systems due to circulating currents are not a factor with dc cables. (However, ac circulating currents can be eliminated with open-circuit sheath designs.)

A major advantage of dc cables is that their performance is not limited by ac charging current. This effect reduces the ratings of ac circuits and eliminates them from consideration when designing long underwater cables. For underground systems, reactive compensation can be installed periodically along an ac cable.[6] However, additional costs for land, reactors, cable terminations, and losses are incurred at each compensation station.

Other items that must be considered in the design of underground transmission systems are reservoirs for self-contained oil-filled systems and pumping plants for high-pressure oil-filled pipe-type cable systems. Some designs may use manholes, although they are optional. There is little difference between ac and dc systems in this regard. The environmental effects of underground cables are minimal, and they can be considered identical when comparing ac cables and dc cables with a metallic earth return. Solid extruded dielectric cables are not suitable for dc systems because of space charge retention in the polymer.

Land requirements are higher for dc substations than for ac substations. For example, in one design, 16.2 ha (40 acres) was required for a dc 4000-MW system versus 8.1 to 10.1 ha (20 to 25 acres) for an ac substation of the same rating.[4] The use of compact designs can reduce the land requirements for both ac and dc substations.[7,8]

4.3 CONVERSION OF OVERHEAD AC LINES TO DC

The construction of new transmission lines has become increasingly expensive and time consuming, requiring up to eight years from project conception to commissioning. The acquisition of new ROW is difficult if not impossible under certain circumstances, particularly with increasing environmental concerns.

The conversion of existing ac lines to dc provides a feasible option for increasing transmission capacity at a relatively low cost and with short lead times. This, of course, requires that ac transmission lines already exist in the route of the power interchange. As a minimum, limited change could be made to the transmission line, with the principal investment being the new converter stations. In some cases, additional modifications can be made to the line to further increase power capacity.

The nature of dc transmission allows operating at a higher "root-mean-square" (rms) voltage and current than is possible with ac transmission over the same line. Consequently, power transfer is significantly increased. The economic advantages of the power interchange capability will often result in the rapid payback of the converter and line modification expenses. In addition, the well-documented operational advantages of dc transmission can be realized.

There are many instances in which the addition of an EHV ac transmission network has reduced the loading of the underlying transmission system. These lines, built as the principal transmission system many years earlier, now carry power at levels well below their capacity. The conversion of these underloaded circuits can achieve an even greater increase in usable capacity than would be obtained by converting an ac line that is heavily loaded. Whereas ac power flows as a result of voltage, phase angles, and impedances, dc power is both directed (over the line) and controllable.

4.3.1 Relative Loadability

The National Electric Safety Code treats the maximum operating voltage of a dc line as equivalent to the maximum ac line-to-ground crest operating voltage for determining minimum clearance requirements. Temporary overvoltages are usually not a significant factor in dc line insulation since dc system voltages are well controlled by the converters. Transient overvoltages on dc lines are typically caused by a surge induced on the healthy pole by a ground fault on the other pole of a bipolar line. This surge is moderate in magnitude [~1.7 per unit (pu)], and the waveshape produces less risk of flashover than a typical ac circuit switching surge. Consequently, an ac line converted to dc operation can at a minimum typically operate at a pole-to-ground voltage equal to the crest phase-to-neutral ac voltage for which it was designed. In cases where the limiting line insulation criteria are creepage and contamination, further increases in dc operating voltage are possible by reinsulating the line with high-creepage insulators.[9]

Alternating-current transmission line loading is generally limited by voltage regulation, stability, and phase angle considerations to levels considerably less than the thermal limit. This is particularly true of EHV lines, where the minimum conductor diameter is often established by corona criteria. Series and shunt compensation can be used to increase the loadability of ac lines.

Direct-current conversion allows controlled loading of a line up to the thermal limit, without the stability, phase angle, and voltage regulation problems associated with ac lines. Although increased line current increases power losses, the economic benefits of providing the increased transmission capacity with less lead time and at lower initial cost than a new ac or dc line may often prevail over loss considerations. The absence of skin effects causes the dc resistance of conductors to be slightly less than the ac resistance. The lower resistance will produce less power loss and, consequently, less temperature rise for direct current as compared to alternating current. This will allow a slightly higher thermal current limit.

The power capacity increase resulting from conversion will vary considerably with transmission line and system characteristics, as well as the configuration selected for dc operation. Conversion of a typical transmission line to dc operation at the thermal limit will typically increase power transfer capacity to three (and perhaps more) times the ac circuit's surge impedance loading.[10] This assumes that two phases are used as dc poles and that one phase is used as a metallic return conductor.

4.3.2 Line Modification

Very little change is required in the transmission line to permit dc operation. The existing tower structures and conductors can be used without change.

Ordinary ac insulators do not have adequate contamination performance to exploit the maximum dc voltage permitted by the line clearances. When the line is retrofitted with fog-type ac insulators or special dc insulators, a dc operating voltage up to 150% of the line's rms line-to-line ac voltage may be possible. Both insulator types provide the additional creepage distance to resist contamination effects.

In high-contamination areas, leakage currents can corrode the pins of ac insulators used on dc lines. This corrosion can lead to a loss of the insulator's mechanical strength, and expansion of the corroded pin can crack the insulator porcelain. A special insulator is available which uses a sacrificial zinc sleeve to alleviate this corrosion problem.

Conductor changes and the necessary tower structural reinforcements to support more or larger conductors can be made in some cases to increase the capacity and reduce the losses of the converted line. The economic trade-offs of this major modification can be analyzed on a case-by-case basis.

4.3.3 Environmental Considerations

As previously discussed in Sect. 4.1, the nature of dc line environmental performance is quite different from that of an ac line. The underlying corona discharge phenomena causing these effects operate differently for ac and dc. Also, the differing effects on animate and inanimate objects of the static and alternating electric field suggest a less stringent field criterion for dc lines.

In general, an ac line converted to dc at the previously described voltage levels will have acceptable performance, but regulatory agencies will usually require detailed analysis of the environmental effects. The analysis of dc line environmental performance is complex and generally empirical. Considerable research has been conducted on conventional dc line configurations (bipolar line with two conductor bundles at the same height). Scale-model studies, performed at a research facility, may be needed to accurately assess converted line environmental performance.

4.3.4 Line Configuration

A number of options exist for converting three-phase ac lines to bipolar dc configurations.[10] Figure 4.1 shows a single-circuit line conversion requiring only a change of the line insulators, with the center phase providing a permanent metallic neutral. Costs and lead time associated with siting, designing, and constructing an earth electrode can be eliminated by using the metallic neutral.

The center conductors can be operated in parallel with one of the outside conductor bundles, as shown in Fig. 4.2. This unbalanced scheme will produce lower total losses than the configuration shown in Fig. 4.1 but does not increase the maximum capacity. It may be possible on some lines to eliminate the center conductors and add conductors to the outside bundles, as shown in Fig. 4.3. The same conductor weight is supported, but the changed mechanical force distribution will possibly require structural reinforcement. This option will increase the line thermal capacity by 50%.

Another option, illustrated in Fig. 4.4, doubles the conductors in the center bundle. The outer bundles are connected in parallel to form one pole, and the upgraded center bundle forms the other pole. The total conductor weight supported is increased 33%, and structural changes may be necessary. The additional conductors double the line thermal capacity relative to Fig. 4.1.

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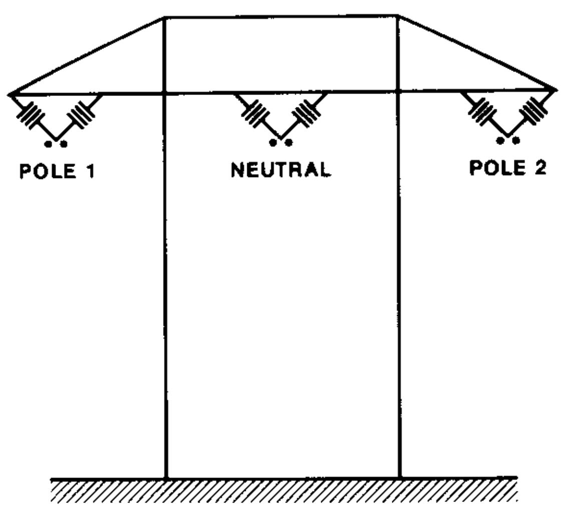

Fig. 4.1. An ac tower converted to bipole with neutral.

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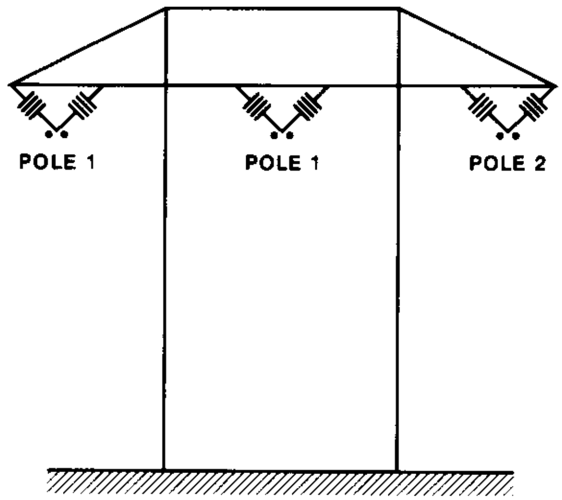

Fig. 4.2. An ac tower converted to bipole.

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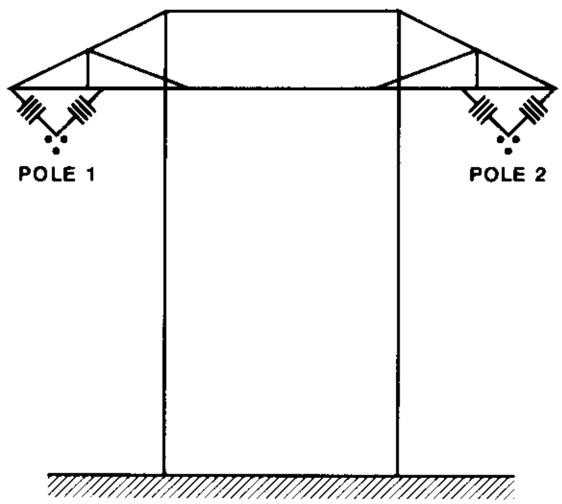

Fig. 4.3. An ac tower converted with neutral removed.

The availability of a double-circuit ac line for conversion allows the simple configuration shown in Fig. 4.5. Two parallel single-circuit ac lines are converted to two high-capacity monopoles in Fig. 4.6.

In many cases, the transmission line or lines being considered for conversion supply ac power to intermediate points along the route. The supply for these buses must be carefully examined to determine conversion feasibility. Alternate sources may be provided for these locations, or additional dc terminals in a multiterminal configuration may be the best solution. Considerable

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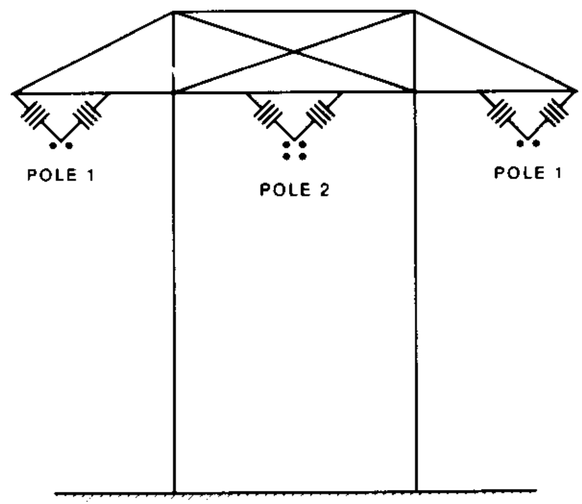

Fig. 4.4. An ac tower converted to bipole with double conductors for pole 2.

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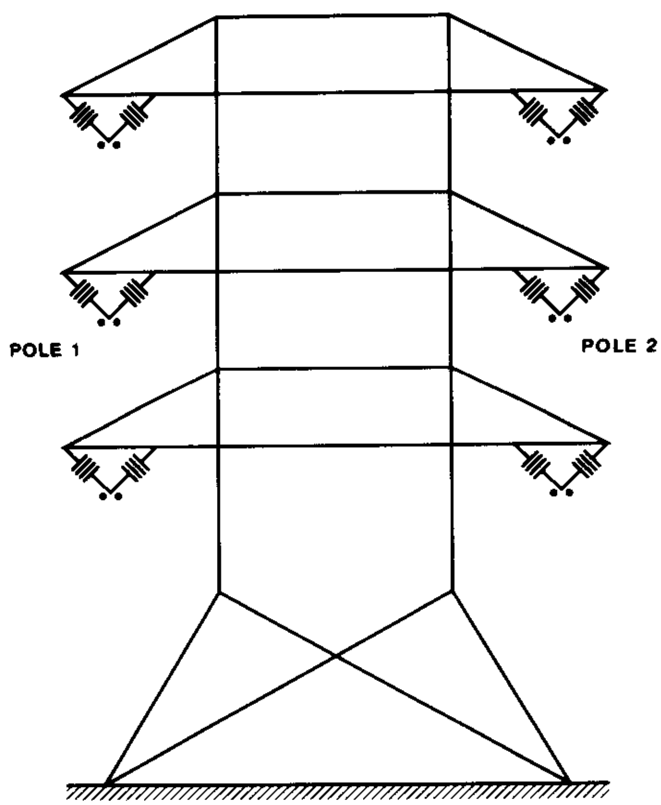

Fig. 4.5. A double-circuit ac tower converted to bipole.

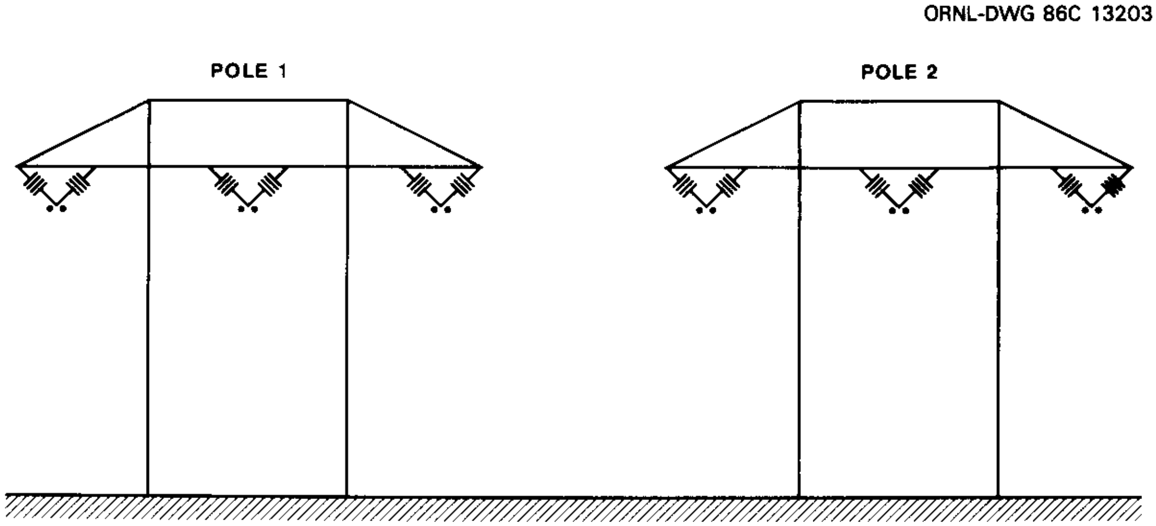

Fig. 4.6. Parallel ac towers converted to bipole.

research and development work on multiterminal dc systems has been performed, and several projects with three or more terminals are presently being designed or constructed. This technology has matured to the point where it is a valid option to be considered when converting lines supplying a number of points.

In some cases, a hybrid line with a dc circuit for through power transfer and an ac circuit for intermediate loads can be advantageous.[5]

4.4 CONVERSION OF AC CABLES TO DC

The conversion of existing ac cables to dc can also provide a feasible option for increasing transmission capacity. Again, the question to be answered is whether the cost of adding the converter stations is justified by the increase in power transmission. This may indeed be the case where the installation costs for new ac cable are high and/or an ROW is difficult to obtain.

The age and condition of the existing cable must be considered. A test program is recommended to determine whether internal ionization is present and whether the original dc test voltages can still be met. Direct-current cable designs do not differ significantly from ac cable designs; so high-voltage ac cables with stabilized insulation may be appropriate for conversion to dc.

Two conversion cases have been studied and are reported in the literature.[11] The first involved a 35-km double-circuit 110-kV oil-impregnated, gas-pressurized cable, with three 800-mm^2 conductors in each of two steel pipes. This system had a maximum capacity of 180 MVA. The cable could be operated at a dc voltage of 180 kV; each conductor could carry 690 A. The power transfer capacity was 740 MW, with the three conductors in each pipe connected in parallel. In the event of a cable fault disabling one three-conductor circuit, the steel pipe housing could serve as a metallic neutral conductor, which would provide a capacity of 280 MW. The equivalent ac alternative (which included compensation) required three additional double circuits and was twice the cost of converting the ac cables to dc.

The second case was a multibus system for a metropolitan 110-kV grid. The need was to reinforce the system to provide for twice the existing load. The cables were single core, oil filled, and naturally cooled. Since no pipe housing was available as a metallic neutral, two of the three ac cables were used as the pole conductors, with the third available as the neutral conductor. Switching facilities were provided at the converter stations.

Again, a dc voltage of 180 kV was selected, and the dc current was 10% greater than the ac current rating. Since dc systems do not contribute significantly to fault currents, it was not necessary to uprate existing ac equipment at the converter terminals. A total of 56.7 circuit-kilometers of dc cable was converted from ac. In contrast, for equivalent operation, 172 circuit-kilometers of ac cable needed to be added. A meshed multiterminal dc system was found to cost 87% of the ac alternative.

Several unconventional attributes of dc systems could be considered in this evaluation. First, since the dc cable flows and converter reactive power requirements can be controlled, it is possible to achieve improved performance via load balancing of the associated ac cable network. Second, in the event of a major disturbance, the controllable dc cable flows can assist in mitigation and/or restoration, especially if an overload capability is designed into the cable and converters.

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5. REACTIVE POWER REQUIREMENTS

When comparing ac and dc alternatives for new or expanded transmission systems, it is usual to specify that they do not impose reactive power requirements on the adjacent systems. In that sense, they are "reactive power neutral"—a comparison between ac and dc will be equivalent regarding reactive power influence. This chapter examines several aspects of reactive power requirements when comparing ac and dc overhead power transmission alternatives.

5.1 REACTIVE POWER REQUIREMENTS OF DC CONVERTER STATIONS

The nature of the conversion process in a Graetz bridge is that current will lag voltage. The controllability of a converter derives from the delayed firing of the valves, by which means the output voltage is controlled from full positive (rectification) to full negative (inversion). The delayed firing causes a delay in the current onset of an incoming valve. On the ac side of the bridge, this delay is reflected as a change in power factor. This is illustrated graphically in ref. 1.

If commutation overlap is ignored, the power factor can be expressed as

$$\cos\phi = \cos\alpha \ , \tag{5.1}$$

where α is the firing delay angle. Including commutation overlap, u, the power factor can be approximately expressed as

$$\cos\phi \approx 1/2[\cos\alpha + \cos(\alpha + u)] \ . \tag{5.2}$$

This is valid within typically 1%. (Exact expressions are derived in ref. 1.)

For an inverter, the above expressions are valid if α is replaced with γ, the inverter margin angle. Both rectifier and inverter consume reactive power.

Another useful expression for reactive power can be expressed as

$$Q \approx P_d\sqrt{\left(\frac{V_{d0}}{V_d}\right)^2 - 1} \ , \tag{5.3}$$

where V_{d0} is the no-load average dc voltage $= (3\sqrt{2}/\pi)E_{ac}$. This equation indicates a nonlinear relationship between Q, reactive power, and P_d, bridge dc power. This is shown in Fig. 5.1. Increased power is accompanied by increased direct current, which will cause an increase in the commutation overlap, u. Thus, reactive power increases faster than real power. Depending on the converter station design, the reactive power requirement at rated dc power will be 0.5–0.6 pu Mvar.

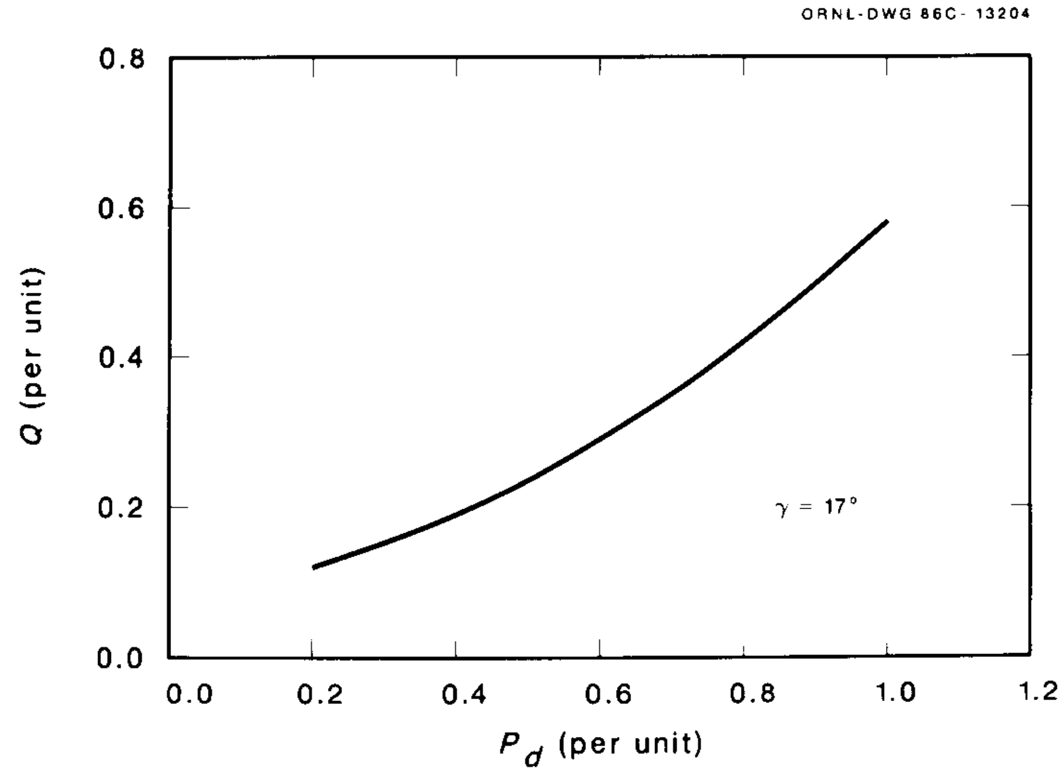

Fig. 5.1. Reactive power as a function of dc power, per terminal.

Sources of reactive power for the converters are as follows:

- harmonic filters (capacitive at 60 Hz),
- shunt capacitor banks,
- adjacent ac network (including generation),
- synchronous condensers, and
- static var compensators.

Reference 2 discusses these sources in detail.

Since the reactive power requirement changes with dc power, it is necessary to provide a means of switching the sources. This switching must be coordinated with ac network filter requirements and also with existing limits on ac bus voltage. At low power levels, some lower limit of filtering will be necessary. The capacitance in that filter bank will have to be sized to supply the minimum required reactive power to the converter. As the power level and dc current increase, so will the filtering and reactive power requirements. Capacitor banks will normally be needed in addition to the filter capacitance.

Weak (high-impedance) ac networks present special concerns since excess voltage excursions can occur during switching or load rejection. Shunt reactors may be advisable; synchronous condensors can provide bus voltage stiffening; and static var systems can provide rapid response via thyristor-switched capacitors or thyristor-controlled reactors.

The converter cost figures developed in Chap. 8 include reactive compensation for "normal" applications. If the converter is placed at a weak ac network location, special compensation may be needed. In this case the converter cost will be at or above the upper limit of the band shown in Fig. 8.1.

5.2 REACTIVE POWER REQUIREMENTS FOR AC TRANSMISSION

In comparing costs of ac and dc transmission, the only reactive power and equipment costs involved are those associated directly with the transmission project under study, that is, the overall incremental costs introduced by the reactive power and equipment requirements of the connecting transmission links only. The internal reactive requirements of the connected networks, although they may be altered by the changed power flows from the transmission link, are not a part of the transmission system.

The evaluation should address the reactive power and equipment requirements introduced by each type of transmission link connecting the same terminal systems or network components at the same power levels.

Analytical means are available for determining the approximate ac transmission reactive power and equipment requirements for 100% power factor operation at the input and output terminals of the link and for load rejection overvoltage suppression. Although these costs are relatively small at natural surge impedance load levels up to distances of about 300 miles, they become significant at much greater transmission distances and at higher load levels.

5.2.1 Impedance Compensation Requirements

Compensation is an important element in generic cost studies for ac transmission. The natural surge impedance loading can be adjusted up or down by shunt or series capacitive and inductive reactances, as shown in Fig. 5.2. Idealized conditions are illustrated. Line series resistance and shunt conductance are neglected and a flat voltage profile is assumed, together with uniformly distributed compensation.

Switching facilities are necessary so that shunt capacitors and inductive reactors can be disconnected whenever they are not needed to perform their design functions of supplying or consuming reactive power.

In an earlier well-documented study,[3] a range of approximate transmission loadability curves was developed. Figure 5.3 illustrates this concept. There is a practical limit of about 67% surge impedance loading (SIL) at 600 miles, uncompensated, at a load angle, δ, within reasonable steady-state limits. A first approximation of the needed compensation over a range of power levels may be estimated from Fig. 5.2.

This family of curves is based on the following idealized conditions: The compensation is assumed to be uniformly distributed, resistance losses are neglected, a flat voltage profile is assumed (the sending and receiving voltages are equal), and there is zero reactive power flow at both line terminals. The curves are developed from the following fundamental relationships (refer to App. B for definitions of the nomenclature) with voltage, V, in kilovolts:

$$P = \frac{(V)^2}{Z_{0c}} = \frac{(V)^2}{\sqrt{X_{LC}X_{CC}}}\ \text{MW}$$

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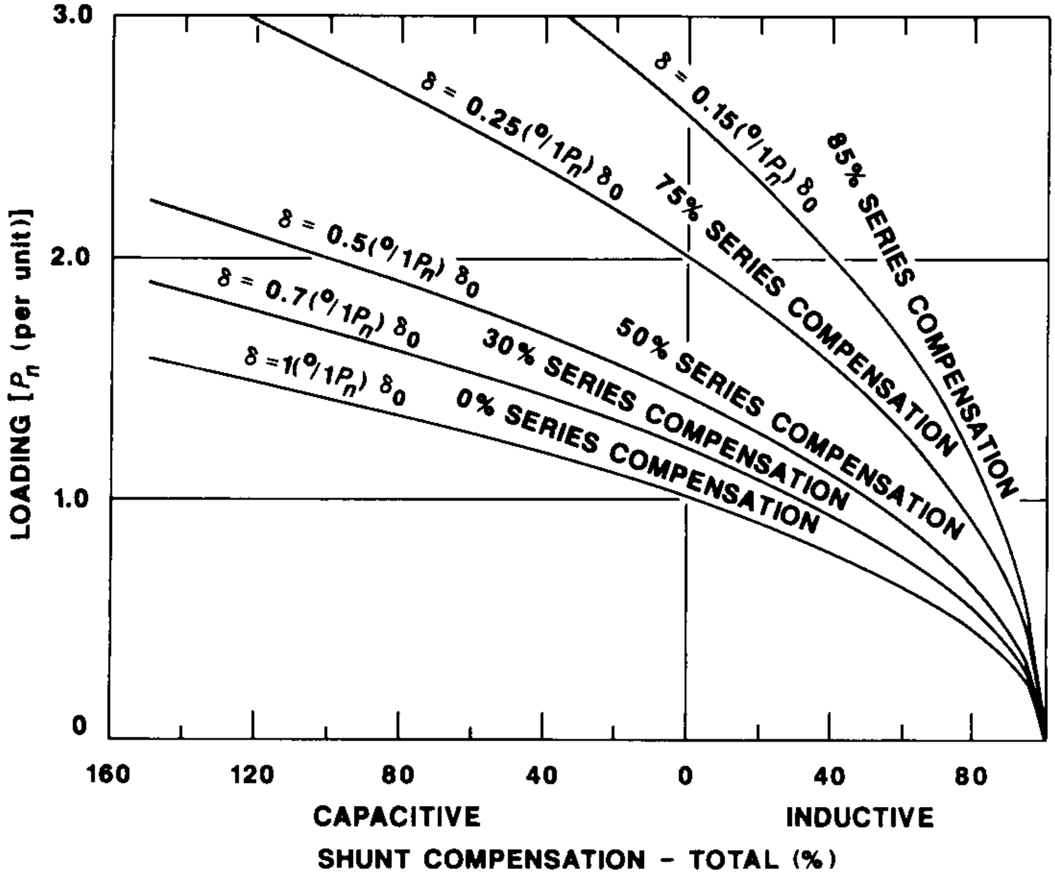

o/1 = PER-UNIT QUANTITY
P_n = NATURAL OR ADJUSTED SURGE IMPEDANCE POWER
δ = CIRCUIT VOLTAGE DISPLACEMENT ANGLE (DEGREES AT P_n)
δ_0 = CIRCUIT VOLTAGE DISPLACEMENT ANGLE (DEGREES AT P_{n0})
P_{n0} = UNCOMPENSATED SURGE IMPEDANCE POWER
E_s = SENDING-END VOLTAGE
E_R = RECEIVING-END VOLTAGE

Fig. 5.2. Compensated transmission performance as functions of series and shunt compensation. Compensation is assumed to be uniformly distributed, and resistance losses are neglected. Flat voltage profile assumed, $E_s = E_R$.

and

$$\delta_0 = (57.3°)D\sqrt{X_{L1}/X_{C1}} \text{ degrees} .$$

5.2.1.1 Voltage class

The voltage class, in kilovolts, for the ac transmission line is estimated from the following approximate relationship:

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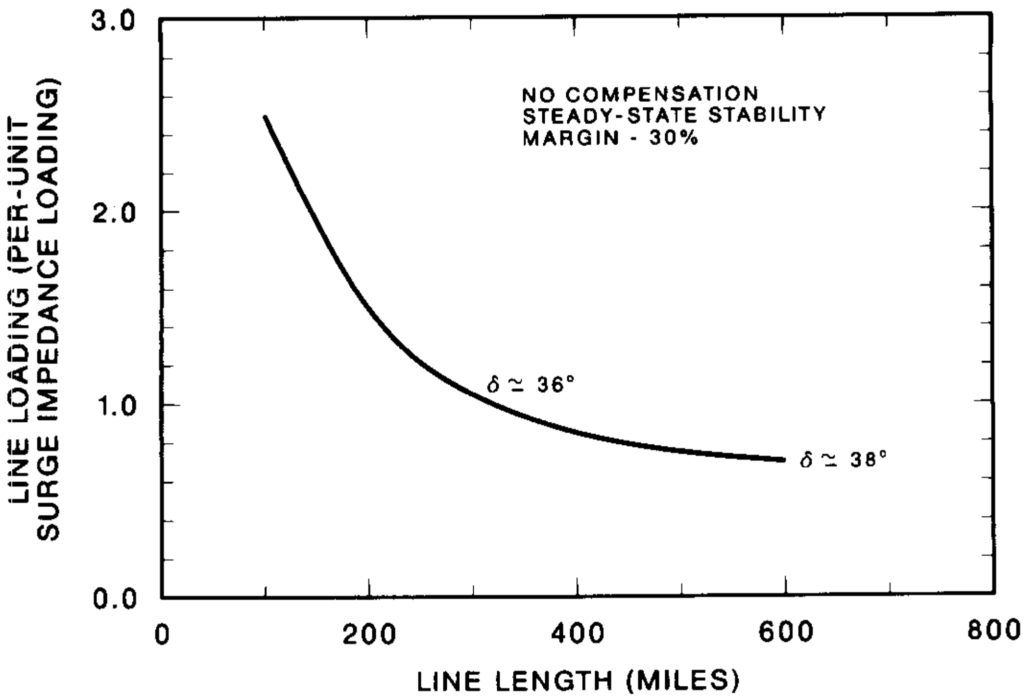

Fig. 5.3. Line loadability curve (heavy loading).[3]

$$V \approx 15\sqrt{\mathrm{MW}} \ .$$

This permits a conductor choice for preliminary design estimates.

5.2.1.2 Series compensation

Usually when the reactive power compensation requirements for a proposed ac transmission circuit are being estimated, the expected maximum steady state line load angle is first established. This permits calculation of any needed series compensation from simple phasor analysis. Line resistance is neglected since the resistance component of the line impedance is usually small for conventional high-voltage transmission and has little effect on the series compensation requirements. Considering the equivalent π circuit without intermediate reactive support, the circuit voltage displacement angle δ is

$$\delta = \sin^{-1} \frac{(I_p \,\mathrm{pu})(X_{LC} \,\mathrm{pu})}{n(E_R \,\mathrm{pu})} \ . \tag{5.4}$$

Then,

$$X_{LC} \,\mathrm{pu} = \frac{n(E_R \,\mathrm{pu})}{(I_p \,\mathrm{pu})} \sin\delta \tag{5.5}$$

$$= (X_L \,\mathrm{pu}) \left[\frac{100 - \%\ \mathrm{comp.}}{100} \right] , \tag{5.6}$$

where % comp. is the ratio of series compensating reactance to the line inductive reactance, expressed in percent of the line reactance, and

$$X_{se}\,\text{pu} = (X_L\,\text{pu}) - \frac{n(E_R\,\text{pu})}{I_p\,\text{pu})}\sin\delta \tag{5.7}$$

= per-unit series compensating reactance

and

$$\text{percent series compensation} = \frac{(X_{se}\,\text{pu})}{(X_L\,\text{pu})} \times 100$$

$$= 100\left[1 - \frac{n(E_R\,\text{pu})\sin\delta}{(I_p\,\text{pu})(X_L\,\text{pu})}\right]\% \ . \tag{5.8}$$

An initial estimate of the needed series compensation is thus developed from the desired circuit or line segment voltage displacement angle δ. The line segment is that portion of the circuit between points of voltage identification or support, $E_S\,(= nE_R)$ and E_R.

Adjustable series inductive or capacitive compensation and phase angle transformation may also be used for load control and system damping, as discussed in a following section.

5.2.1.3 Shunt compensation

Once the series compensation needed to achieve the specified maximum steady-state voltage displacement angle is determined, the shunt compensation necessary for voltage support must next be established. The line resistance will be taken into account here because of its effect on the amount of needed compensation. (See Fig. 5.4 for phasor illustration of shunt compensation.)

The following derivation gives the approximate receiving terminal shunt compensation required at 100% power factor load as a percentage of the total line-only charging current. From simple phasor analysis,

$$\left(\Delta I_{cR} + \frac{I_c}{2}\right)X_{LC} = E_R - n\,E_R\cos\delta + (I_p)R \tag{5.9}$$

and

$$\Delta I_{cR} = \left[\frac{E_R(1 - n\cos\delta) + (I_p)R}{X_{LC}}\right] - \frac{I_c}{2} \ , \tag{5.10}$$

where ΔI_{cR} is the receiving terminal compensating charging current.

$$\frac{\Delta I_{cR}}{I_c} = \frac{(\Delta I_{cR})(X_C)}{E_R} = \frac{X_C}{E_R}\left[\frac{E_R(1 - n\cos\delta) + (I_p)R}{X_{LC}} - \frac{0.5(E_R)}{X_C}\right] . \tag{5.11}$$

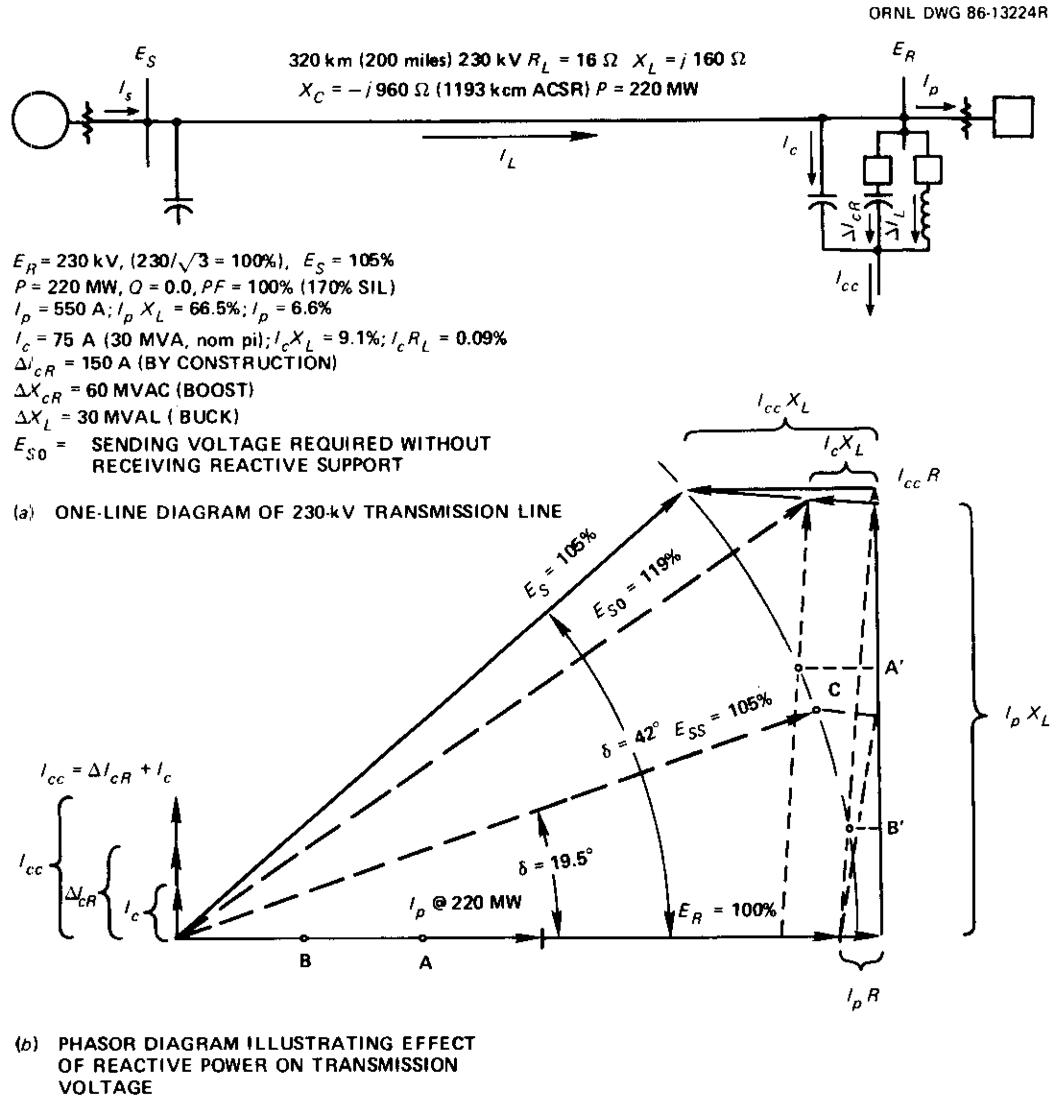

Fig. 5.4. Phasor analysis of power transmission voltage control by reactive power.

Then, for $E_R = 1.0$ pu and all other quantities also in per unit,

$$\frac{\Delta I_{cR}\,\text{pu}}{I_c\,\text{pu}} = \left\{\frac{X_C\,\text{pu}}{X_{LC}\,\text{pu}}\left[1 - n\cos\delta + (I_p\,\text{pu})(R\,\text{pu})\right] - 0.5\right\}100\% \tag{5.12}$$

= percent receiving terminal shunt compensation required in terms of total line-only charging current.

5.2.1.4 Voltage control and reactive power flow

The following approximate phasor analysis of a typical heavily loaded transmission circuit illustrates the critical effects of reactive power flow on such a circuit (see Fig. 5.4). The design load chosen for this example is at unity power factor because transmission delivery of reactive power to a load area is an expensive voltage-degrading practice normally avoided by providing local reactive supply.

The analysis indicates that, at the design load level, 220 MW (about 170% of uncompensated SIL), about 60 MVA of reactive boost must be added to the 30 MVA supplied by line capacitance (nominal pi estimate). This will support a receiving voltage of 100% (230 kV), with the sending voltage at 105% (242 kV). Under these conditions the load angle, δ, would be 42°.

If the load is reduced to 150 MW (points A and A′ on Fig. 5.4), the reactive boost can be reduced to zero for the same voltage condition since the line capacitance is supplying about a 9% voltage boost. With a further load reduction to 75 MW, (points B and B′), the line capacitive support of 30 MVA must be effectively backed down to zero by switching in the 30-MVA inductive reactor. With the load reduced to zero and the shunt reactor on, the receiving voltage would rise to the sending-end value, 105%; with the reactor off, it would rise to about 115%.

Figure 5.4 also indicates that, at the design load of 220 MW, the sending voltage required without the 60-MVA capacitive boost would be about 119%. With the 30-MVA shunt reactor also switched on, it would rise to about 126% to hold 100% receiving voltage.

At the level marked C, the operating point for 50% series capacitor line compensation, the 170%-SIL full design load would still require some reactive boost to maintain the voltage levels chosen. This boost would be reduced from the former 60 MVA to about 17.5 MVA, but the series compensation would require about 72.5 MVA for a total of about 90 MVA capacitive (about 50% more than for the case without series compensation for the same voltage control). However, the load angle, δ, is now reduced to about 19.5°, less than half that for the case without series compensation, essentially doubling the overload capability and stability margin. Depending on other system circumstances, the added compensation costs thus might well be justified.

These cases again illustrate the general criteria that shunt compensation controls voltage while series compensation controls load angle and stability margin.

The simple phasor diagram is thus a very useful tool in visualizing the effects of and estimating the approximate magnitude of required reactive MVA supply and loading in long-distance ac transmission. It also offers an approximate check on conventional calculations.

5.2.1.5 Load-rejection overvoltage suppression

Reactive power compensation of an ac transmission circuit may be used to hold the sending and receiving voltages and the load angle, δ, within acceptable limits when the power loading on the circuit exceeds its natural uncompensated surge impedance loading. Load rejection may also result in the need for reactive compensation when such switching operations cause undesirable overvoltage excursions. If these should reach unacceptably high levels (e.g., greater than about 105% of normal voltage), provision should be made to reduce the overvoltage possibilities by application of shunt inductive compensation or removal of shunt capacitive compensation from the circuit or both. This section explains how to estimate the required shunt reactive compensation for load rejection overvoltage suppression.

Alternating-current transmission line overvoltage excursions are usually made up of two components. The first is the so-called Ferranti Effect caused by quadrature-leading line-charging current flowing through the line inductive reactance. The second is caused by the total line-charging current flowing through the supply source reactance, creating a sending-end voltage increase. The voltage rise is proportional to the ratio of net three-phase line-charging current that appears at load interruption to the terminal bus transient short-circuit current.

The Ferranti Effect component is addressed in the following no-load analysis. In this, a "nominal pi" circuit is assumed, with the circuit series resistance and shunt conductance neglected since they are insignificant. Let

$\Delta X_L\%$ = shunt inductive compensation at receiving terminal, in percent of the circuit total shunt capacitive loading.

ΔMVA_L = shunt inductive (reactive volt-amperes) compensation at receiving terminal, in percent of circuit total charging current at circuit nominal voltage.

I_{L0} = no-load line-charging current, amperes at E_R no load.

Then,

$$100\%\,\Delta MVA_L = \frac{E^2D}{X_{C1}} \text{ MVA at circuit nominal voltage} \; . \tag{5.13}$$

At zero load, the line current (nominal pi) is

$$I_{L0} = \frac{E_R D}{X_{C1}}\left(0.5 - \frac{\Delta X_L\%}{100}\right) \tag{5.14}$$

and the inductive voltage rise is

$$E_{L0} = I_{L0}(X_{L1}D)\left(1 - \frac{X_{se}\%}{100}\right) \tag{5.15}$$

$$= \frac{E_R D^2}{X_{C1}}\left(0.5 - \frac{\Delta X_L\%}{100}\right)X_{L1}\left(1 - \frac{X_{se}\%}{100}\right) \; .$$

The load rejection receiving voltage, E_R, then is

$$E_R = E_S + \frac{E_R D^2}{X_{C1}}\left(0.5 - \frac{\Delta X_L\%}{100}\right)X_{L1}\left(1 - \frac{X_{se}\%}{100}\right) \; . \tag{5.16}$$

From the above,

$$E_R - E_S = E_R D^2\left(0.5 - \frac{\Delta X_L\%}{100}\right)\left(1 - \frac{X_{se}\%}{100}\right)\left(\frac{X_{L1}}{X_{C1}}\right)$$

and

$$\Delta X_L\% = \left[0.5 \frac{(E_R - E_S)}{E_R D^2\left(1 - \dfrac{X_{se}\%}{100}\right)} \cdot \left(\frac{X_{C1}}{X_{L1}}\right)\right]100 \; , \tag{5.17}$$

the percent shunt inductive compensation, $\Delta X_L\%$, required at the no-load receiving terminal to limit the line-only voltage rise to

$$\frac{(E_R - E_S)}{E_S} 100\% \ .$$

This expression is indeterminant for 100% series compensation because then $E_S = E_R$; that is, there is no net line series reactance to produce a charging-current voltage rise.

5.2.2 AC Transmission Power Flow Control

Alternating-current transmission line power flow is closely approximated by the expression

$$P_R = \frac{E_S E_R}{X_{LC}} \sin\delta \ , \tag{5.18}$$

where

E_S and E_R = line sending and receiving terminal voltages,
X_{LC} = line net inductive transfer reactance between terminals,
δ = voltage angular separation between the two systems or regions at the interconnection points, that is, the angular difference between the sending and receiving system voltages (load angle).

In the typical cases of synchronous interconnections between major power systems or between separate regions of the same coordinated system, the only factor in the above power transfer equation available for flexible, independent power flow control of substantial range, other than phase shift by transformation, is the transfer reactance X_{LC}. The angle δ is largely controlled by the individual systems or regions and by power flow over other interconnection paths.

The net transfer reactance X_{LC} can be controlled over a wide range by series capacitive and inductive reactances. For example, a series compensation range of 60% capacitive to 60% inductive would give a power flow range of 4 to 1 for specific values of terminal voltages, E_S and E_R, and an angular separation δ. This range could be obtained in perhaps 7.5% power steps based on uncompensated power flow. It would be accomplished by a proper choice of switched series capacitor and reactor banks, each of which would be fitted with appropriate protective equipment. Such a system would facilitate power flow control in a manner similar to voltage control by on-load transformer tap changing and by reactive power control.

If desirable, the step changes could be reduced by introducing "vernier" series reactance by transformation with on-load tap changing or by static var type of control. With the latter, this reactance component of the series compensation could be modulated to aid system damping as required. Such a system for modifying the transfer reactance over a wide range could facilitate power flow scheduling by selecting the required amount of compensation as needed to meet the schedule.

High-speed insertion of series compensation under certain transient load or fault conditions could effectively improve stability margins. If thyristor switching were employed, "bang-bang" techniques would be effective in suppressing system power oscillations.

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6. POTENTIAL COST REDUCTIONS IN DC SYSTEMS

Direct-current power transmission is a continually evolving technology; yet almost all systems to date have basically the same configuration and mode of operation as the earliest systems. However, the potential exists to reduce costs substantially while at the same time improving the performance and security of the system. This chapter sets forth a number of unconventional system and control arrangements. Techniques considered include receiving-end control, unit generation and diode rectifier operation, use of converters in voltage and reactive power control, and forced commutation.

6.1 RECEIVING-END CONTROL

The conventional way of operating a dc transmission system is with the inverter stations as close to their limit of security as possible (i.e., margin angle control), thereby using the inverter equipment efficiently (i.e., highest dc voltage), with minimum reactive power consumption and minimum harmonic generation. The current in the dc line is then controlled by adjustment of the rectifier end voltage. This conventional characteristic is shown in Fig. 6.1.

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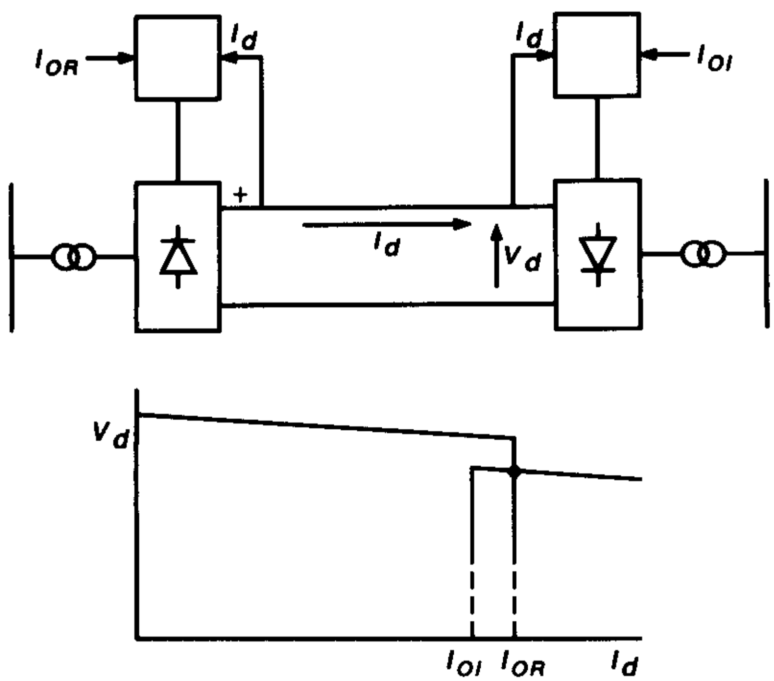

Fig. 6.1. Rectifier current control. (I_{OR} = current order-rectifier; I_d = direct current; I_{OI} = current order-inverter; and V_d = direct voltage.)

In the event of a decrease in rectifier voltage, it is also conventional to transfer current control to the inverter and voltage control to the rectifier (minimum firing-angle limit). This "mode shift" is as indicated in Fig. 6.2.

This accepted mode of control provides satisfactory performance under normal conditions, especially for strong ac receiving systems. As the ac system becomes weaker (higher impedance) or as the dc system becomes stronger, the following characteristics may need attention:

1. *Commutation failures.* When the inverter is operating at its maximum voltage, it is vulnerable to commutation failures. If an extinguishing thyristor is not given a reverse voltage long enough to completely establish forward voltage blocking capability, the thyristor may continue to conduct, and a commutation failure ensues. A distortion in the ac voltage may provoke a commutation failure, and major faults (e.g., ac system faults) are invariably accompanied by such events.

2. *Control stability limitations.* Since the dc line and terminal equipment (smoothing reactor and dc line filter) present a system with both capacitive and inductive elements, it can be seen that the low-frequency negative resistance characteristic of an inverter operating on the margin angle limit can present difficulties. The weaker the ac system (see Fig. 6.3), the more difficult it becomes to ensure appropriate damping and stability at the natural frequencies of the line and terminal equipment.

3. *Rectifier valve requirements.* In systems designed for unidirectional power flow, the requirements for the rectifier valves are typically more severe than for the inverter. The dc

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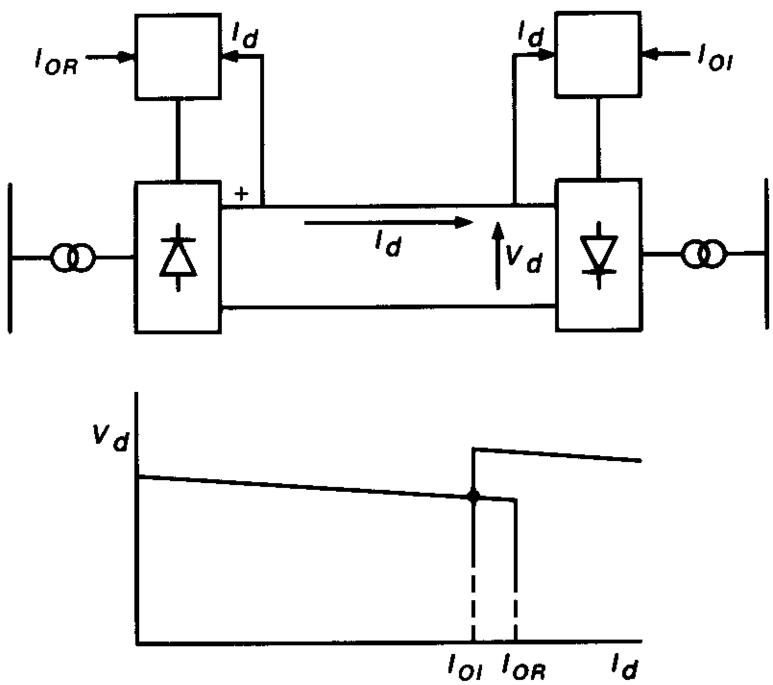

Fig. 6.2. Inverter current control. (I_{OR} = current order-rectifier; I_d = direct current; I_{OI} = current order-inverter; and V_d = direct voltage.)

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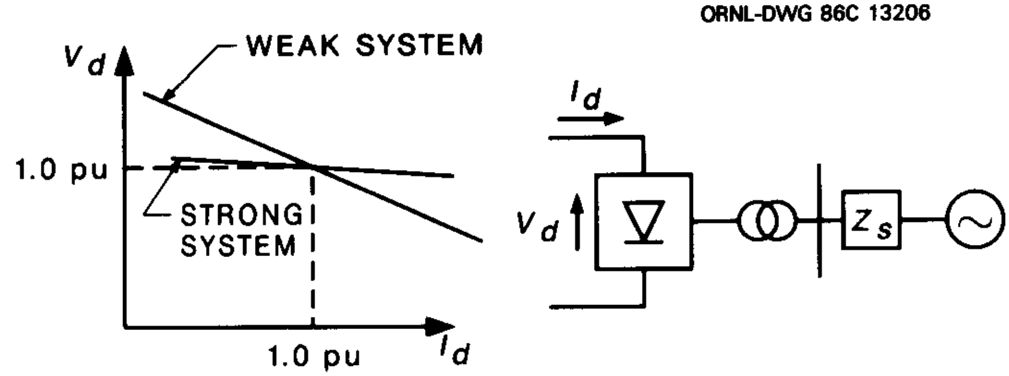

Fig. 6.3. Regulation characteristics of an inverter. (V_d = direct voltage; pu = per unit; I_d = direct current; and Z_s = ac system impedance.)

voltage is higher at the rectifier by the amount of the line drop. The system damping will be lower at the rectifier (since there will be little local load), resulting in higher transient voltages. Also, surge current ratings are higher at the rectifier.

4. *Communication requirements.* To properly utilize the controllability of a dc system, it should respond quickly and appropriately to disturbances in the ac system. If current modulation is requested in a conventional system, that information must be communicated to the rectifier. This will incur a time delay. Further, care must be taken to modulate within the current margin (Fig. 6.1) so as to not lose the operating point.

An alternative to the conventional control mode of Fig. 6.1 is that of Fig. 6.2, normally considered to be a backup operating mode. The rectifier operates at its minimum firing angle, while the inverter operates at a firing angle greater than its margin angle. Thus the inverter controls dc current, the rectifier controls dc voltage, and the rectifier has a (positive) current margin. The rectifier controls current in the event of a decrease in inverter voltage.

This operating mode can minimize the limitations mentioned above.[1,2] It also can enable reduced harmonic generation and reactive power consumption at the rectifier. However, there will, in turn, be increased valve stresses and losses at the inverter, together with increased harmonic generation and reactive power consumption. In parallel multiterminal systems with two or more inverters, at least one inverter will be current controlling, with all of the above advantages and disadvantages.

6.2 UNIT GENERATION AND DIODE RECTIFIER OPERATION

If the control mode of Fig. 6.2 is taken one step further, one can consider the mode shown in Fig. 6.4. Here, the rectifier does not have a backup current control but instead always operates at its minimum firing angle. This can now be achieved with an uncontrolled converter, or diode rectifier. Current control is exercised from the inverter, with the advantages and disadvantages as outlined in Sect. 6.1.

The absence of the control function at the rectifier would appear to be a great disadvantage; however, techniques for achieving the necessary responses have been developed and tested on a dc system simulator.[3] The following commutation failures and fault recoveries were addressed:

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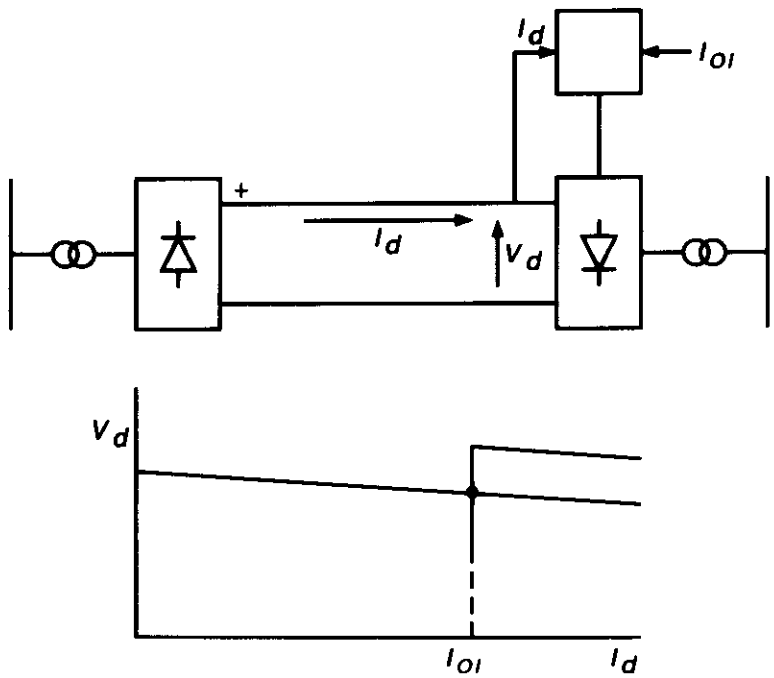

Fig. 6.4. Diode rectifier with inverter current control. (I_d = direct current; I_{OI} = current order-inverter; and V_d = direct voltage.)

- *Commutation failure*—Using typical parameters for the machines and converters (i.e., generator subtransient reactance, 0.2 pu, and transformer reactance, 0.2 pu), the maximum dc-side short-circuit current is less than three times the rated current. Given an inverter with a margin angle of 20° and commutating reactance of 0.2 pu, a dc current of 3.8 pu was tolerated without failing commutation. With the inverter in current control, the margin angle is higher than is usual in conventional operation; therefore, the incidence of commutation failures would be lower and recovery could be faster (i.e., no mode shift).

- *Fault recovery*—It could be presumed that the diode rectifier would have to be supported by a dc circuit breaker in order to clear dc line faults and sustained commutation failures. However, the transmission can also be blocked by operation of the ac circuit breakers associated with the generators and reestablished without significant voltage and current transients by operation of the same breakers. The bridge diodes form a very effective bypass path during the interruption, reducing considerably the duty imposed on the breaker (i.e., it has only a diverting duty).[3]

However, operation of the ac breakers alone could leave a slowly decaying dc current "freewheeling" through the diodes because of the energy stored in the line and inductance. This current could be reduced quickly to zero by inserting a resistive component into the current loop to absorb the energy. This could be achieved by including an energy-absorbing dc circuit breaker in the loop, or possibly it could take the form of an additional duty for a metallic return transfer breaker (MRTB), which may be present anyway.[4]

The concept of the diode rectifier can be expanded to include a set of unit generators, as shown in Fig. 6.5. Since the harmonic generation is minimized, it may be possible to remove the ac filters. Since valve firing occurs at a low voltage and a minimum firing angle, the reactive power is also reduced. If the generators are designed to accept the harmonic currents and provide the reactive power, then the unit generator concept may be viable.[5]

Several additional advantages can now be claimed:

- The basic insulation levels (BILs) of the converter equipment can be reduced.
- Machine self-excitation is eliminated.
- One stage of transformation is removed.
- Fault currents will be reduced.
- Alternating-current switching equipment is reduced.
- The ratings of the remaining equipment are reduced.

Thus, there can be a substantial cost reduction attributed to the above advantages, plus a reduction in station losses, which translates to a reduction in capitalized expenses. There will be some savings in reduced control equipment, but this is not a major factor. A dc circuit breaker, if needed, will compensate for some of the savings. Overall station reliability can be expected to increase because of the simplifications. Maintenance requirements will be reduced.

It is apparent that this concept is valid only for unidirectional power transmission. The diode converter cannot function as an inverter since the diodes are unable to block forward voltage.

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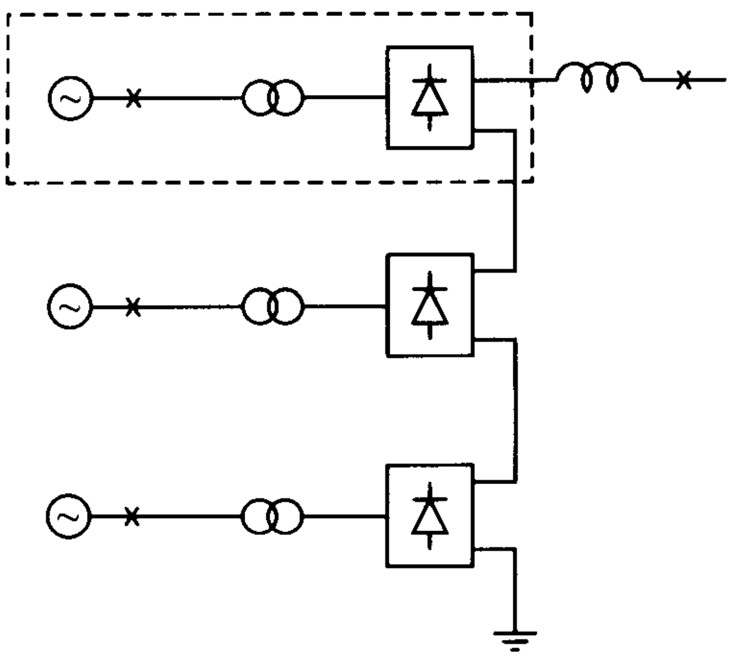

Fig. 6.5. Unit generator-diode rectifier arrangement.

6.3 USE OF THE CONVERTERS IN VOLTAGE AND REACTIVE POWER CONTROL

In the conventional control mode, changes in dc voltage or current cause changes in reactive power at both the rectifier and the inverter ac buses. These reactive power changes will affect the ac bus voltage, with the amount of change dependent on the ac system strength. Filter and capacitor bank switching is coordinated with changes in current/reactive power to keep voltage excursions within specified limits. In especially weak locations, it may be necessary to install synchronous condensers or static compensators. It is possible to operate the dc transmission in modes where the reactive power does not change significantly, reducing the negative effects and therefore the compensation requirements. Proposed control modes that could be considered include constant reactive power control, constant voltage control, and independent operation of converter bridges.

6.3.1 Constant Reactive Power Control

Consider the mode of operation described in Fig. 6.6. If the inverter is controlled to keep the reactive component of current injected into the ac system constant, the dc-side inverter voltage/current characteristic follows the indicated curve.[1]

If a conventional current control characteristic is maintained at the rectifier, the power flow across the system can be controlled by adjusting the current reference. The reactive power consumption (at both terminals) is then defined by the inverter constant reactive power characteristic. The reactive power characteristic can be displaced by adjusting the appropriate references. The reactive power would then be supplied by capacitors, switched as necessary.

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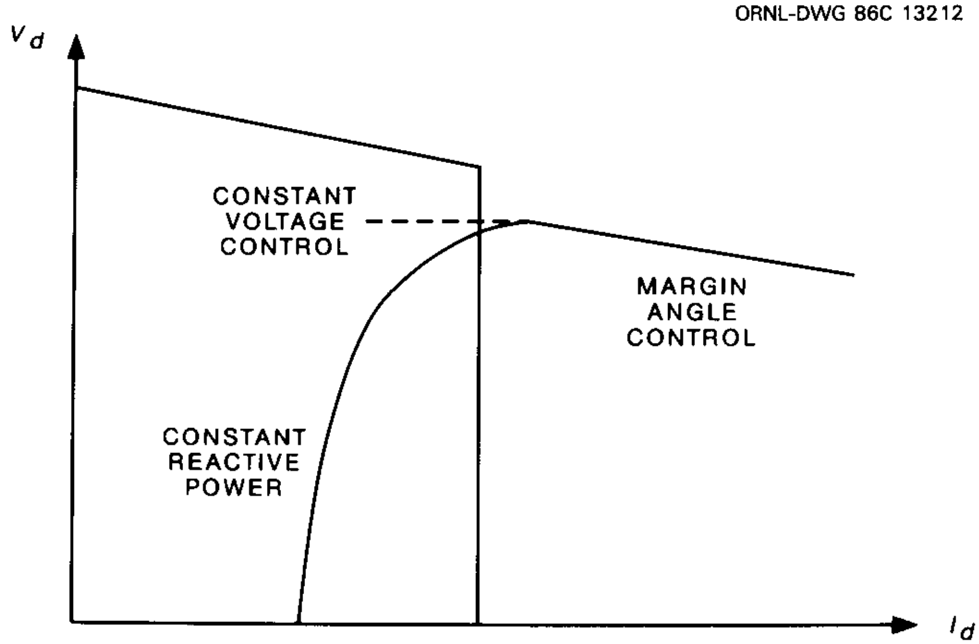

Fig. 6.6. Alternate control modes. (V_d = direct voltage and I_d = direct current.)

It should be noted that both the rectifier and inverter operate with positive resistance characteristics, resulting in extremely stable operation. As the inverter operates with a margin angle in excess of the minimum, the incidence of commutation failures would be lower. However, the reactive power requirement will be in excess of that needed for operation at minimum margin angle.

6.3.2 Constant Voltage Control

As an alternative to constant reactive power control, it is possible to operate with constant voltage control. If, by this, one refers to ac voltage, then it is accomplished by monitoring the bus voltage and adjusting the margin angle.[6] This adjustment (or gamma modulation) changes the reactive power, affecting the ac voltage accordingly. This can be achieved by means of an auxiliary control loop that forces the converter to operate similarly to a static var compensator. The margin angle range will have an effect on the valve design: A wide range will produce higher voltage stresses and higher losses.

It is also possible to have a control characteristic whereby the inverter controls the dc voltage. This is also shown in Fig. 6.6. Again, since the margin angle departs from its minimum value, the reactive power required will exceed the nominal value.

6.3.3 Independent Operation of Converter Bridges

It is conventional to operate all the bridges in a converter terminal with the same firing angle. However, it is also possible to independently operate the bridges, thereby providing a wider range of real and reactive power control at the receiving terminal.[2]

In Fig. 6.7 it can be seen that the load current is made up of two components that, while having the same magnitudes (for the same transformer tap-changer position), differ in phase. This provides the capability of adjusting the magnitude and phase relationship of the total current relative to the

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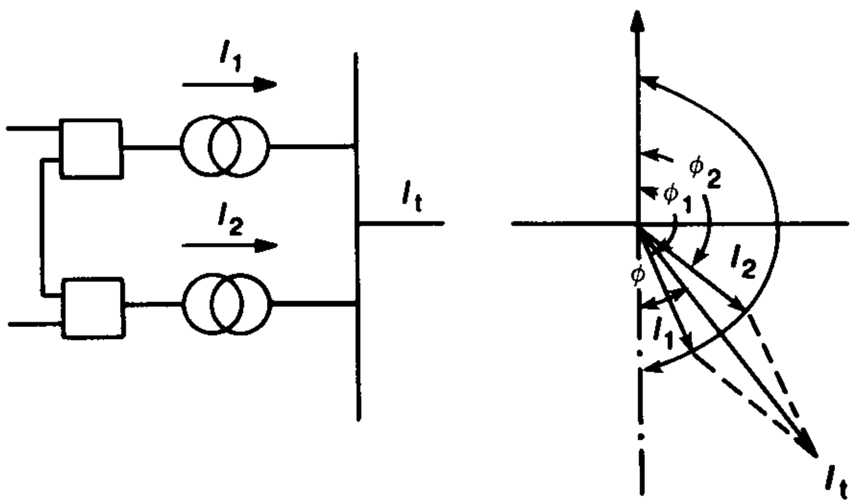

Fig. 6.7. Independent operation of converter bridges.

ac bus-bar voltage. For example, this feature might be used to control the ac voltage while changing power levels.

If the bridges are 6-pulse units, then there is no cancellation of the fifth and seventh harmonics (etc.) even with wye-wye/wye-delta transformers. The economics of using two 12-pulse bridges is questionable since systems with voltages up to 500 kV now use single 12-pulse bridges.

6.4 FORCED COMMUTATION

Although force-commutated converters have been used in low power applications, as yet they have not received consideration for HVDC conversion. With recent advances in thyristor valve design, it is possible that such techniques could now be realized. This would result in reductions in reactive power requirements and a less vulnerable inverter.[7] In fact, a force-commutated inverter can supply reactive power. One technique involves the use of a bypassing circuit for force commutating the valves of a conventional dc converter bridge, as shown in Fig. 6.8. Main valves are extinguished by temporarily bypassing the dc line current from the converter (i.e., similar to a conventional block and bypass operation), and the current is then reestablished in the appropriate main valves at the appropriate instant in time.

With such control of the valve firings, it is possible to operate the converter with the phasor current relative to the ac voltage in any of three quadrants: rectifier lagging, inverter lagging, and inverter leading. Since valves can be extinguished, recovery from faults and disturbances is fast and secure, and operation into very weak systems is possible.

Results of a simulator investigation[2] of the recovery from a single-phase, zero-impedance, fault to ground at the ac bus-bar of an inverter supplying an inductive load (power factor, 0.7) in a receiving system with no machines present (i.e., zero short-circuit ratio) showed that recovery occurs within a cycle of the removal of the fault and with very little trailing disturbance. Forced-commutated and naturally commutated converters could then be combined.[2,8] This hybrid arrangement provides independent real and reactive power control at a dc terminal, as illustrated in Fig. 6.9. This configuration may be economically competitive in weak system applications with a conventional converter plus a synchronous condenser. Additional valves and an energy storage

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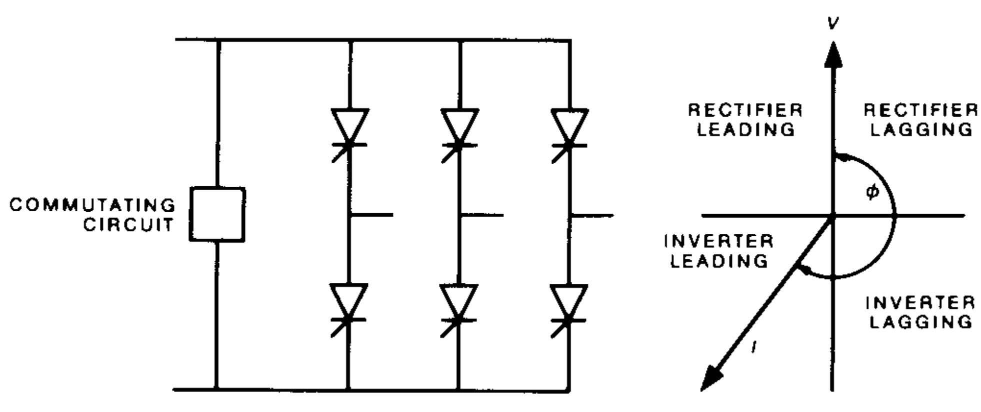

Fig. 6.8. Force-commutated converter bridge.

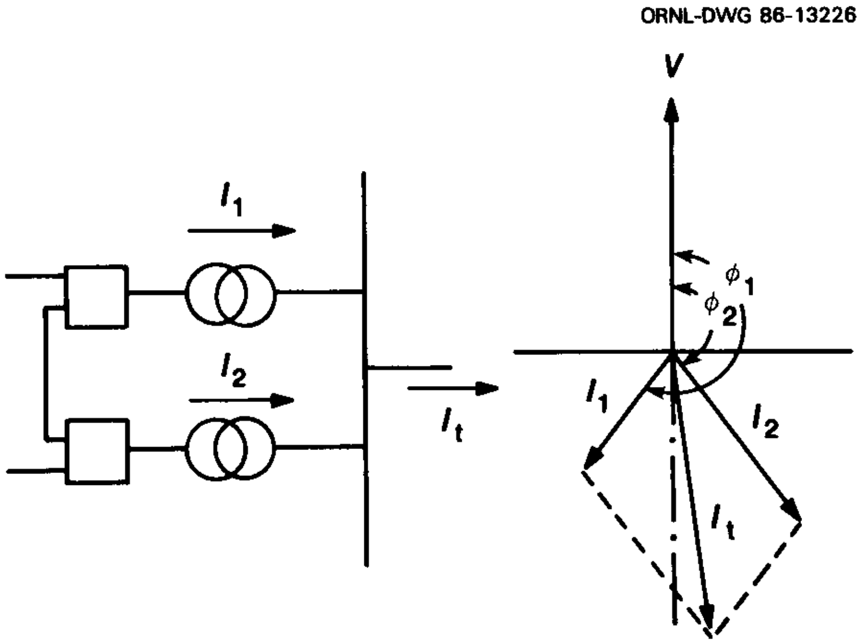

Fig. 6.9. Combination of force-commutated and naturally commutated converters.

element are required for the commutating circuit. Overvoltages are a concern, especially accompanying dc fault currents or large current order changes.

6.5 REFERENCES

1. J. P. Bowles, "Alternative Techniques and Optimization of Voltage and Reactive Power at HVDC Converter Stations," *Proceedings, IEEE Conference on Overvoltages and Compensation on Integrated AC–DC Systems*, Winnipeg, Canada, July 1980.

2. J. P. Bowles, "Unconventional System and Control Arrangements for HVDC," pp. 293–313 in *Urban Applications of HVDC Power Transmission*, proceedings of a symposium held at Philadelphia, Pa., on Oct. 24–26, 1983, sponsored by the Division of Electric Energy Systems, U.S. DOE, October 1983.

3. J. P. Bowles, "Multiterminal HVDC Transmission Systems Incorporating Diode Rectifier Stations," *IEEE Trans. Power Appar. Syst.* **PAS-100**, 1674–81 (April 1981).

4. J. P. Bowles and S. Nilsson, "Several Possible Applications of DC Circuit Breakers," pp. 425–44 in *Incorporating HVDC Power Transmission into System Planning*, proceedings of a symposium held at Phoenix, Ariz., on Mar. 24–27, 1980, sponsored by the Division of Electric Energy Systems, U.S. DOE, March 1980.

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8. K. S. Tam and R. H. Lasseter, "A Study of a Hybrid HVDC Converter," pp. 205–12 in *Proceedings, International Conference on DC Power Transmission*, Montreal, Canada, June 1984.

Part II

ESTIMATING AC AND DC SYSTEM COSTS

7. BULK POWER TRANSPORT COSTS

Direct cost comparisons between dc and ac alternative solutions for an energy transport problem are an essential part of the decision-making process. The operational costs and benefits deriving from each of these options should also be carefully examined and evaluated to fix as closely as possible the probable total investment plus operating costs. The failure to take these into account can lead to significant add-on costs for the solution or mitigation of operating problems.

7.1 COST FACTORS TO CONSIDER

To make direct cost comparisons, estimates for the main system elements must be developed for each of the technologies under consideration. For the dc alternative, capital funds for construction of the converter terminals, ac input/output equipment and facilities, the ground electrodes, and the interconnecting transmission line must be evaluated. The capitalized cost of converter and transmission line losses will need to be calculated. Savings may result from deferred investment if staged construction is appropriate.

Estimates for the main elements of an ac transmission system include the installed costs of the step-up and step-down transformers, the overhead line itself, light-load compensation if required, reactive power compensation as necessary to permit economy loadings above the natural surge impedance load level, circuit breakers (including disconnect switches, relaying and control, buses, structures, etc.), and buildings and site development. Again, capitalized losses will need to be determined.

Stability control may add large investment costs or impose constraints on power system operation. Among the methods for increasing stability control on an ac system are rapid adjustment of reactive power by high-speed switching of shunt compensating devices, by switching in or out of service portions of series compensation stations, or by using static var compensators. The inherently high level of controllability of dc systems allows operating strategies that have been successfully applied to enhance ac system dynamic stability and thus permit higher ac line loadings.

Often during initial economic studies, approximate installed cost estimates are made to establish the initial "ball-park" investment level and the equipment and line approximate ratings. For example, voltage levels to transmit a given amount of power for a range of loss costs or loss values can be calculated, or determinations can be made of optimum power transmission levels for assumed operating voltages and loss costs. Procedures will be developed in the following sections to illustrate ways of determining these values.

From such calculations, preliminary judgments as to the preferred alternatives may be made, and the total annual costs may then be compared. At this point, improving the accuracy of the estimates would be necessary. For example, comparisons could be made between dc converter costs and line costs. Cost reductions from a lower converter voltage counterbalance the greater capital cost of the line when increasing the line conductance and lowering the line operating voltage to achieve the same power transfer capability. More accurate estimates can take into account the particular requirements and siting constraints of the stations and the lines. Line cost estimates should reflect the cost impacts of the terrain over which the line is expected to pass, as well as any environmental impact costs. As previously mentioned, an important requirement in defining the ac transmission option is the application of reactive power compensation to increase the loadability of the transmission system. Light-load, economic loading, and contingency situations should also be analyzed to determine the amount and type of compensation needed. Capital and operating costs must be evaluated in the process of selecting the most economic ac transmission design and in comparing this design with the most economic dc option.

Other important considerations that are likely to influence costs include possible power system operating scenarios. Estimates should be made of the costs/benefits from the solution or mitigation of probable operating problems. Typical of these solutions might be the control of system dynamic or transient stability, finding ways for the reduction of large circulating currents, or the prevention of excessive generation resource loss, which is often followed by large load shedding during major disturbances.

During the preliminary planning stages, assumptions must be made because of uncertainties in forecasting. These assumptions should provide value ranges to account for probable effects of such sources of uncertainty as[1]

- the technical effects of translating general performance specifications into detailed engineering designs,
- estimating errors resulting from incomplete information,
- the economic effects of changes in projected prices of materials, labor, and land, and
- unexpected weather conditions, unanticipated regulations, and political events that could drastically change the commercialization timetable and costs.

The various categories of ac and dc plant investment as well as control or mitigation of operating problems are discussed in the following chapters of this report. Table 7.1 lists the items that could be examined and evaluated when comparing ac and dc options for electric power transmission. (This table was previously presented as Table 1.1 and is repeated here for convenience.) The consideration of applicable elements should yield a reasonably comprehensive picture of the total life-cycle costs/benefits from either choice and thus permit an informed comparison of the two technologies.

7.2 REFERENCES

1. *Technical Assessment Guide,* Electric Power Research Institute, Technology Evaluation Group, Planning and Evaluation Division, Palo Alto, Calif., 1982.

Table 7.1. Generic cost comparison elements

System cost elements for given power (MW) transmitted and line length	
AC	DC
Right-of-way	Right-of-way
Load density per acre of right-of-way	Load density per acre of right-of-way
Transmission voltage	Transmission voltage
Line—Conductors Towers	Line—Conductors Towers
Substations or switching stations	HVDC converter stations
Breakers and disconnects Transformers Reactive power (capacitive and inductive)	Breakers and disconnects Transformers Filters and var supply
Shunt capacitors and reactors Series capacitors Static var systems	
	Valve assembly and smoothing reactor Ground electrode and metallic return transfer breaker
Protection Control Station civil works	Protection Control Station civil works
Losses—Line Station	Losses—Line Station
Communications	Communications
Operating characteristics	Operating characteristics
System reinforcement	System reinforcement
Environmental impact	Environmental impact
Consequences and recovery from	Consequences and recovery from
Short-duration line faults Long-duration line faults	Short-duration line faults Long-duration line faults
Stability enhancement	Stability enhancement
Dynamic Transient	Dynamic Transient
Recovery from system breakup	Recovery from system breakup
Fault magnitude and breaker interrupting duty	Fault magnitude and breaker interrupting duty
Energy availability	Energy availability
Ease of tapping for intermediate loads	Ease of tapping for intermediate loads
	Conversion of ac lines to dc

8. AC STATION COSTS

Utilities are expected to have access to current installed cost figures for conventional ac equipment. For convenience, a brief tabulation of cost ranges for switching and substation equipment is presented here.

8.1 INTRODUCTION

Alternating-current switching and substation plant investment may include the costs of the following major items:

- power circuit breakers,
- power transformers,
- disconnect switches,
- reactors,
- shunt capacitors,
- static var systems,
- synchronous compensators,
- series capacitors,
- buswork,
- protection and control systems,
- structures, and
- control houses.

The installed cost of each of these items includes costs of material or equipment, construction, land, material handling, surveys, and, usually, overhead charges.

Because of the uncertainties previously discussed, attempts to predict costs with great precision are rarely justified for early planning estimates. However, as suggested in connection with transmission line estimates, the cost forecasts for substations can also be refined as better information develops and uncertainties diminish.

8.2 EQUIPMENT COST ESTIMATES

Table 8.1 lists manufacturers' approximate prices (FOB Destination) for ac high-voltage transmission substation components.

8.3 INSTALLED COSTS

Total installed costs for typical ac equipment in a substation for comparisons of ac and dc may be estimated with sufficient accuracy for planning purposes from the unit cost assumptions in Table 8.2. This avoids unnecessarily complex cost breakdowns.

8.4 REFERENCES

1. *Technical Assessment Guide*, Electric Power Research Institute, Technology Evaluation Group, Planning and Evaluation Division, Palo Alto, Calif., 1982.

Table 8.1. Equipment cost estimates for ac high-voltage transmission substation components

Type of equipment	Capacity (kV)	(kV)	Cost ($)
Power Circuit Breakers	230	63	125–175K
	345	63	150–200K
	500	63	275–350K
	765	40	375–450K
Load Interrupters	230		70–90K
	500		190–225K
	765		225–300K
Group-Operated Disconnects	230		24–30K
	500		30–35K
	765		45–60K
Autotransformers without LTCs	230		3–4/kVA
	345		2–3/kVA
	500		2–3/kVA
	765		2–3/kVA

Table 8.2. Estimated installed costs of ac equipment

Type of equipment	Cost ($)
Circuit breaker	
345 kV	700–800K
500 kV	1400–1600K
765 kV	1800–2000K
Bulk power transformer	
345 kV	3–4/kVA
500 kV	4–5/kVA
765 kV	5.50–6.50/kVA
Shunt capacitors	6–6.50/kVA
Series capacitors	7–9/kVA
Static var systems	20–40/kVA
Shunt reactors	12–14/kVA

For example, the estimates for circuit breakers and power transformers include the approximate costs of related control and protection, buswork, disconnect switches, related structures, and a portion of the control house. Allowances for construction, land costs, material handling, surveys, and overhead charges are added to the totals. Similar assumptions apply to the capacitors, static var systems, and reactors.

These estimates are extrapolated from utility planning information and the Electric Power Research Institute's *Technical Assessment Guide.*[1]

9. DC STATION COSTS

One key component in making an economic comparison between the ac and dc transmission options is the cost of the dc converter stations. This chapter outlines some of the basic considerations and factors involved in developing preliminary dc station costs and presents data for formulating initial estimates.

9.1 INTRODUCTION

The distribution of costs of the components is different for ac and dc systems. For an ac system, the line costs predominate, and ac terminal costs are relatively small. For a dc system, the terminal costs may dominate, and they could readily be comparable to the line costs. Consequently, the approximate determination of dc terminal costs should be done early in the process of comparing the two options.

Cost figures presented here are the total installed costs of the converter terminals, including the ac switchyard, harmonic filters, a var bank to compensate to unity power factor, transformers, converters, ground electrodes, communications, and buildings. Also included are preliminary system studies and engineering. Land costs and financing costs are not considered, but site preparation and project management are included. The percentage of each main component cost relative to the total station cost is given in Table 9.1.

Based on a general knowledge of the system requirements represented by the power transmission level, dc line voltage, and ac system voltages, it is possible to estimate the costs of a particular station, provided there are no unusual requirements with a significant economic impact. A preliminary estimate may have a tolerance of $\pm 10\%$. This range represents the influence of specific requirements such as availability specifications or special commercial considerations. The objective

Table 9.1. DC system costs as a percentage of total project costs

Equipment	Percentage of total cost
Converter transformers	20–25
Valves (including controls and cooling)	20–30
Filters and var supply	5–20
Miscellaneous (communications, dc reactor, arresters, relaying, etc.)	5–15
Engineering (system studies, project management)	2–5
Civil work and site installation	15–30

of the rationale outlined below is to make it possible to quickly obtain a preliminary dc station cost that can be combined with other pertinent information to decide whether more detailed studies are warranted. As specifications are refined, more accurate cost estimates can be developed with the help of potential vendors.

It is useful to develop dc converter station costs as related to the system power rating, the dc voltage, and the ac voltage supplied to the converter station. Although some items (e.g., control and protection, ground electrodes) are weakly correlated to the above parameters, essentially these three factors form a reasonable base from which to make estimates.

9.2 POWER RATING

The base case selected is a 500-MW, 1000-A, ±250-kV dc system connected to two 230-kV ac lines. It is assumed that there is one 12-pulse bridge per pole. The ac system is not weak; that is, no special reactive power compensation problems exist. The cost of this converter station is 1.0 pu, which is converted into dollars per kilowatt. This information is presented in Fig. 9.1. Although the cost-versus-power function is not a continuous curve as indicated, this approximation can be used for feasibility studies as a first approximation.

The data in Fig. 9.1 can also be used to estimate the cost of a back-to-back installation. The nature of a back-to-back system allows for selection of the most economical dc voltage such that the full current-carrying capacities of the thyristors are utilized. Other savings accrue from using a smaller smoothing reactor and eliminating the dc filter. There are also savings in the construction requirements, such as the need for only one building. Consequently, the dollars-per-kilowatt costs are less than for a point-to-point system of equal power rating. A multiplier of 0.8 is a good approximation for converting the per-unit costs of the curve to a back-to-back application.

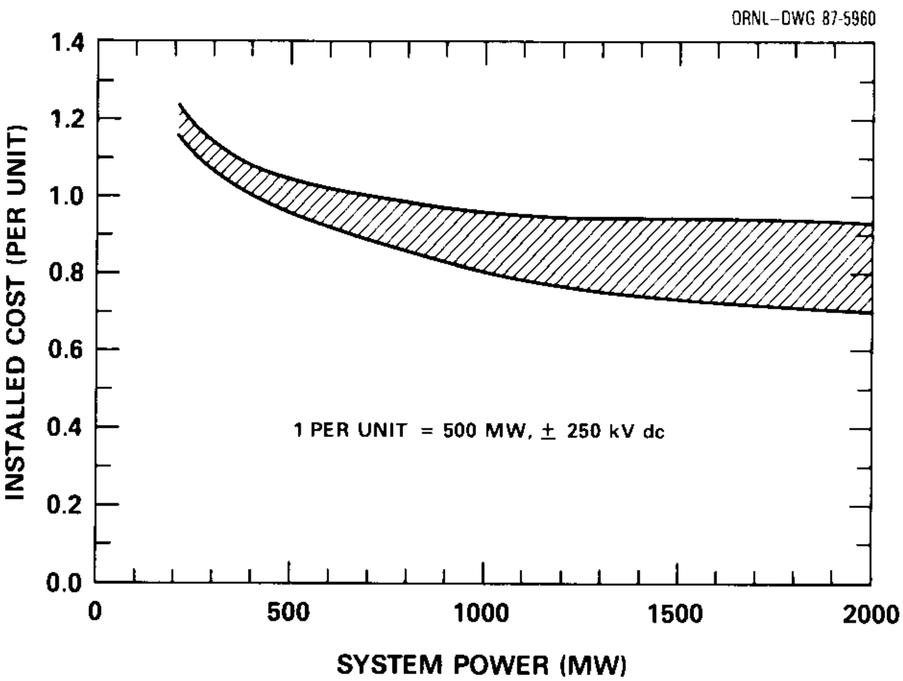

Fig. 9.1. Installed per-unit cost versus system power for point-to-point transmission.

9.3 DC VOLTAGE

The second most influential factor affecting terminal cost is the dc voltage selected. For a given power rating, there is an optimum voltage to minimize terminal costs. However, converter design voltage and current can be readily varied; thus, the converter design can be picked to minimize the total system cost. When the cost-versus-voltage curve for the transmission line is plotted together with that of the converter, an optimum system voltage can be determined. Hence, the final dc voltage chosen for the terminals is usually set by transmission line considerations. For back-to-back installations, where there is no line, the dc operating voltage is chosen to minimize converter costs. Since converter costs increase with voltage, the optimum design reflects a high current at a lower voltage.

Figure 9.2 shows the relationship between dc pole voltage and installed per-unit cost. For this curve, the 1-pu pole voltage has been set at 250 kV dc. As the figure shows, increasing the voltage to 500 kV would result in a 20% increase in terminal costs for a fixed power rating. This increase is primarily due to the larger number of thyristors required to increase the valve voltage. In practice, the voltage dependence of the terminal costs is not a continuous function; however, Fig. 9.2 can be used to give a good approximation.

9.4 AC VOLTAGE

Just as the dc voltage affects the cost of the terminal by its influence on the dc equipment design, the ac bus voltages to which the converters are connected also affect costs. Figure 9.3 shows the relationship between ac bus voltage and installed terminal costs. The cost for the 230-kV ac connections has been established as 1 pu. At higher voltages the terminal cost increases, primarily because of the increasing cost of filter and var banks and converter transformers.

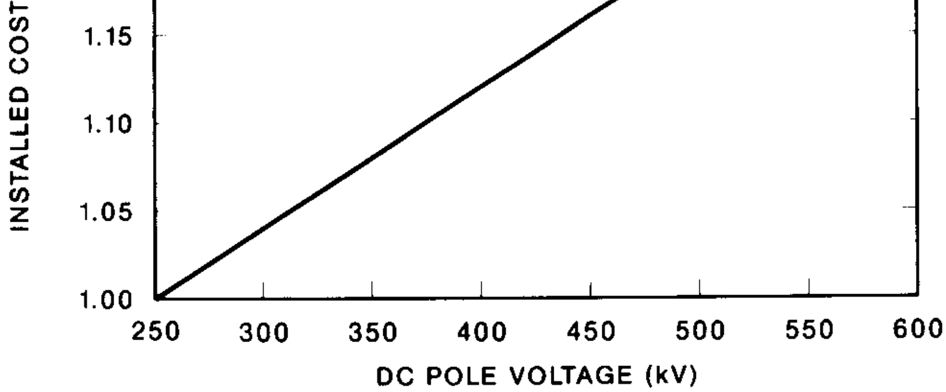

Fig. 9.2. Installed per-unit cost versus dc pole voltage for point-to-point transmission.

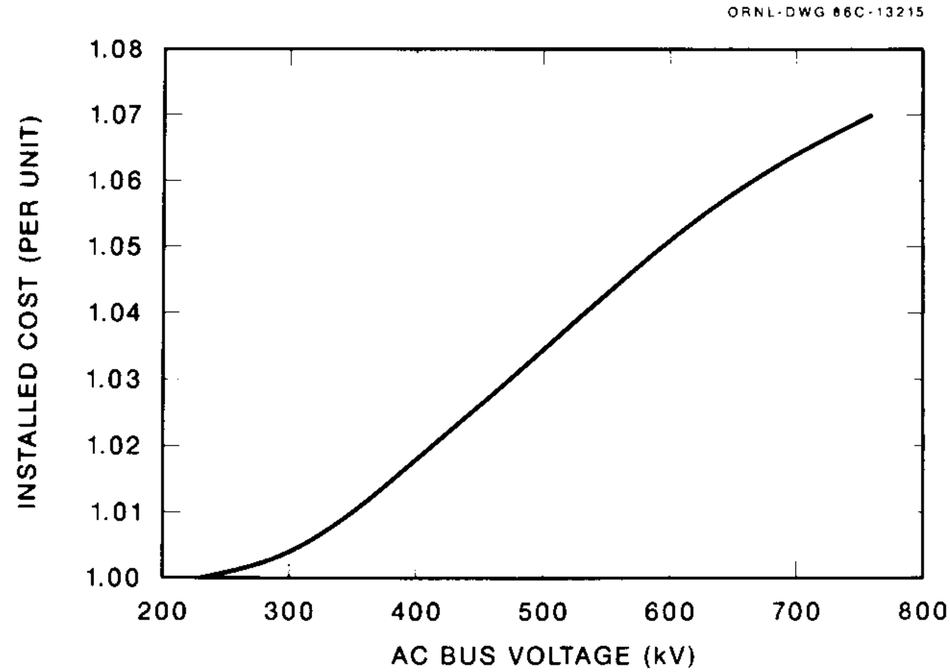

Fig. 9.3. Installed per-unit cost versus ac bus voltage.

9.5 OTHER CONSIDERATIONS

In addition to power level and dc and ac voltages, many other factors can influence installed terminal costs. Among these are

- low ac system short-circuit ratio,
- special ac or dc filter criteria,
- high loss evaluation,
- high availability requirement,
- overload capability,
- restrictive flicker requirements,
- unusual test requirements,
- high BIL levels,
- short construction schedule, and
- unusual spare parts requirements.

The determination of converter losses is important since these would need to be capitalized. The losses in a converter are attributable to the valves, converter transformers, ac filters, and smoothing reactor. Full-load losses can range from 0.7 to 0.9% of a terminal's full-load rating. The harmonics generated by the converter will require special consideration when calculating the total equipment losses. Note that losses must be calculated for each converter terminal, whether back-to-back or point-to-point.

The spread in the curves of Fig. 9.1 is attributable to these factors, with the uncertainty increasing at higher megawatt ratings. It is not possible to generalize cost information for these kinds of specialized requirements. Each such application needs to be individually analyzed to determine the economic impact of these factors.

9.6 CALCULATION OF DC CONVERTER STATION COST

The curves in Figs. 9.1 to 9.3 enable converter station costs to be calculated in per unit as a function of dc power, dc voltage, and ac voltage. To convert from per unit to dollars, it is necessary to have an approximate dollar-per-kilowatt figure to use.

A survey of recent contract prices for dc systems has been taken, and manufacturers of dc equipment have been queried as to their current pricing. A "best estimate" in 1985 dollars for the per-unit dollars per kilowatt is \$100 for both (two) terminals of a point-to-point system. Therefore, in Fig. 9.1, 1 pu = \$100/kW. (Note that this is for two terminals rated ±250 kV, 1000 A, and 500 MW, considered here to be a 1.0-pu rating.) (It is interesting to note that this dollar-per-kilowatt amount corresponds exactly to that in Fig. 1 of ref. 1, published in 1980. Figure 2 of that paper illustrates how the cost of converter stations has increased over time at a rate considerably less than that of conventional ac equipment. Documentation of converter costs is sparse; refs. 2 to 4 contain some cost information.)

Table 9.2 presents two examples of how to use Figs. 9.1 to 9.3 to determine dc converter station costs. The figure of \$100/kW is the 1985 estimated manufacturer's turnkey price for two converter stations on a point-to-point system. The cost to the utility to buy the system and put it into operation will be higher. Additional factors to be considered are the costs of initial studies, preparation of specifications, land, financing, construction management, and commissioning.

Table 9.2. Example calculation of dc station cost

Example 1

Using Figs. 9.1 to 9.3, the preliminary station costs for a 1000-MW, ±500-kV dc point-to-point transmission system connected to 345-kV ac buses would be determined as follows:

a. From Fig. 9.1 for 1000 MW, the \$/kW cost range in per unit is 0.82 to 0.96.

b. From Fig. 9.2 for 500 kV dc, the multiplier is 1.2.

c. From Fig. 9.3 for 345 kV ac, the multiplier is 1.01.

d. The \$/kW cost range in per unit for the system is then 0.99 [0.82 × 1.2 × 1.01 = 0.99] to 1.16 [0.96 × 1.2 × 1.01 = 1.16].

e. Using 1985 costs (1 pu = \$100/kW), the preliminary estimate for the cost of both dc stations is \$99 to \$116 million.

Example 2

The cost range for a 1000-MW back-to-back terminal connected to 345-kV ac buses would be determined as follows:

a. From Fig. 9.1 for 1000 MW, the \$/kW cost range in per unit is 0.82 to 0.96.

b. From Fig. 9.3 for 345 kV ac, the multiplier is 1.01.

c. For a back-to-back system, the multiplier is 0.8.

d. The \$/kW cost range in per unit for the terminal is then 0.66 [0.82 × 1.01 × 0.8 = 0.66] to 0.78 [0.96 × 1.01 × 0.8 = 0.78].

e. Using 1985 costs (1 pu = \$100/kW), the estimated cost range is \$66 to \$78 million for the back-to-back station.

The actual additional cost will also depend on the utility's prior experience with dc systems. The utility may, if not experienced in dc transmission, choose to have major participation (including project management) by a consulting company. Alternatively, the utility may choose to have its own construction team install nearly the entire station. Experience and standard utility practice will dictate how to proceed.

9.7 MULTITERMINAL SYSTEMS

Additional factors arise when estimating the cost of tapped multiterminal dc systems. If the tap rating is small compared to that of the main terminals, then the tap will be disproportionally expensive.[5] For parallel tapping, the following comments apply:

1. The tap will have to be rated for the full line voltage even though its power rating may be low (e.g., 500 kV for a 250- to 500-MW tapping).
2. The number of thyristors in a valve will need to be nearly equal to the number in the main terminals.
3. Transient overcurrents can be high following commutation failures.
4. A neutral conductor may be required to avoid ground current for an outage of one pole of a tap.

It is estimated that a 500-MW tap will cost 75% of a 1000-MW main terminal for a 500-kV dc system.

For series tapping, the following comments apply:

1. The entire converter terminal must be insulated to line potential.
2. A wide range of firing-angle operation must be possible.
3. A wide range of reactive power supply is required.
4. Line losses will be high.
5. Converter losses will be high.

Series-connected tappings can be expected only for small fractions (20% or less) of the system rating. Their cost, likewise, is out of proportion to their ratings.

Direct-current circuit breaker availability may influence the acceptability of multiterminal dc systems.[6–8] The cost of a dc breaker can be estimated on the basis of its constituent parts (interrupter, commutating capacitor, energy absorbers, spark gap or closing switch, preinsertion resistor), which are similar to components found in ac systems. The cost of a breaker rated 500-kV, 4000-A interrupting capability, two-cycle operation, 10-MJ energy absorption is of the order of $500,000 (per pole). Direct-current breaker cost is not expected to be a significant factor when compared to the overall multiterminal system cost.

9.8 SUMMARY

The information presented in this chapter shows that, with few inputs and simple calculations, the dc station costs required for a preliminary economic analysis can be quickly obtained. An example of this calculation is shown in Table 9.2. The cost-per-kilowatt factor may be found to change over time as the dc technology continues to develop. Inflation and international currency exchange rates will also require consideration.

Numerous calculations may be required for both ac and dc alternatives until the optimum system is determined. Only then can a reasonable comparison be made. Even so, dc systems are not always selected on the basis of simple costs. The operational incentives for dc implementation are significant, and the ac alternative may be complex and costly. Consequently, any system evaluation must also include an analysis and evaluation of the technical considerations.

The costs and relationships discussed in this chapter assume conventional dc converter station designs. The new and innovative approaches described in Chap. 6 could well lead to savings in comparison with the conventional dc systems discussed in this chapter.

9.9 REFERENCES

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10. TRANSMISSION SYSTEM COSTS

The development of electric power transmission systems has progressed to the point where power system planners may have a choice between ac and dc transmission. The dc alternative is particularly attractive for long distances—overhead, under water, or urban underground—as well as for asynchronous interconnections. This chapter will discuss costs for overhead transmission lines and underground transmission cables.

10.1 INTRODUCTION

When developing the design of a dc transmission facility, prime consideration must be given to the difference in voltage of maximum economy for the desired capacity and given distance. In general, the most economic line voltage is a function of the square root of the required capacity, while the most economical terminal voltage is essentially the lowest practical, governed largely by the ampere capacity of the converter thyristors. This means that the best terminal voltage is roughly proportional to the required capacity.

Since the terminal cost (two terminals) will typically be a major part of the total project cost, perhaps 50% or more, it is important to achieve a compromise voltage that results in a minimum total transmission facility annual or capitalized cost. The compromise will usually be lower than the best for the line but higher than the best for the terminals. Possible future capacity expansion must be considered in the final choice to avoid the resulting economic penalties. This concept is illustrated in Fig. 10.1.

For the ac alternative, particularly for long distances, the most economical design will usually involve the application of series or shunt compensation and in all likelihood will require load rejection or light-load as well as normal-load reactive voltage control. Approximate equivalent "surge impedance" loading is usually the most attractive in that it results in a good voltage profile and can be obtained over a wide range of loads by adjusting the line surge impedance with series or adjustable shunt compensation.

Reactive power requirements in the load areas of the power system require careful study as well. Ideally, reactive compensation should be available at the points of use to avoid economic and technical penalties from attempts to transmit reactive power appreciable distances over the transmission system. For the best performance of a transmission line (compensated or uncompensated), its load power factor should be held close to unity.

10.2 OVERHEAD LINE COSTS

Transmission line costs may be estimated on the basis of either their capitalized or their annual costs. Each of these, as shown in App. A, comprises essentially two elements, the capital investment (or the annual amount required for its amortization) and the capitalized value of the annual operating cost (or the annual operating costs). (See Fig. 10.2.)

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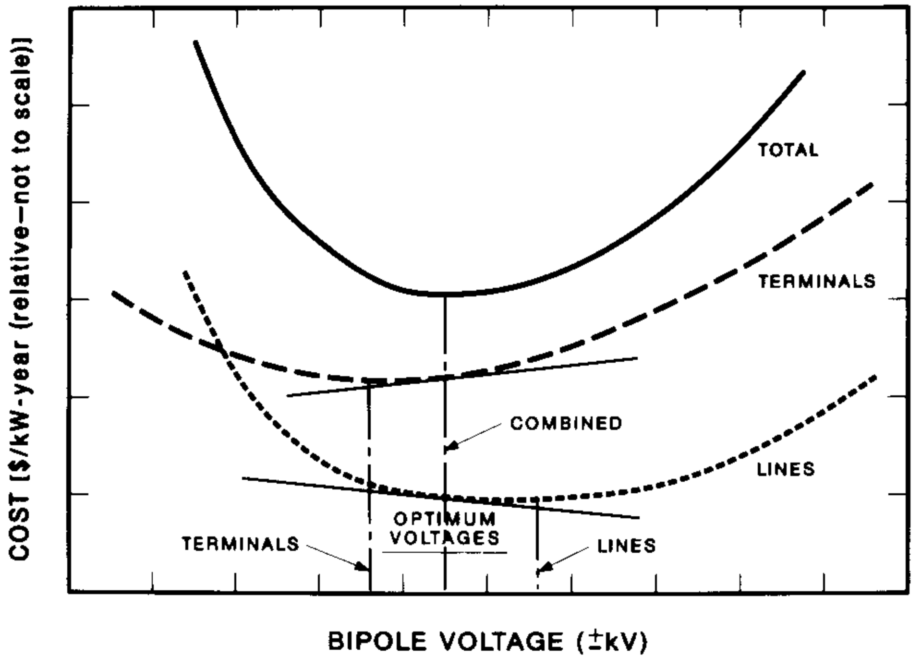

Fig. 10.1. Relative cost trends in dc transmission lines and converter terminals (MW capacity = constant).

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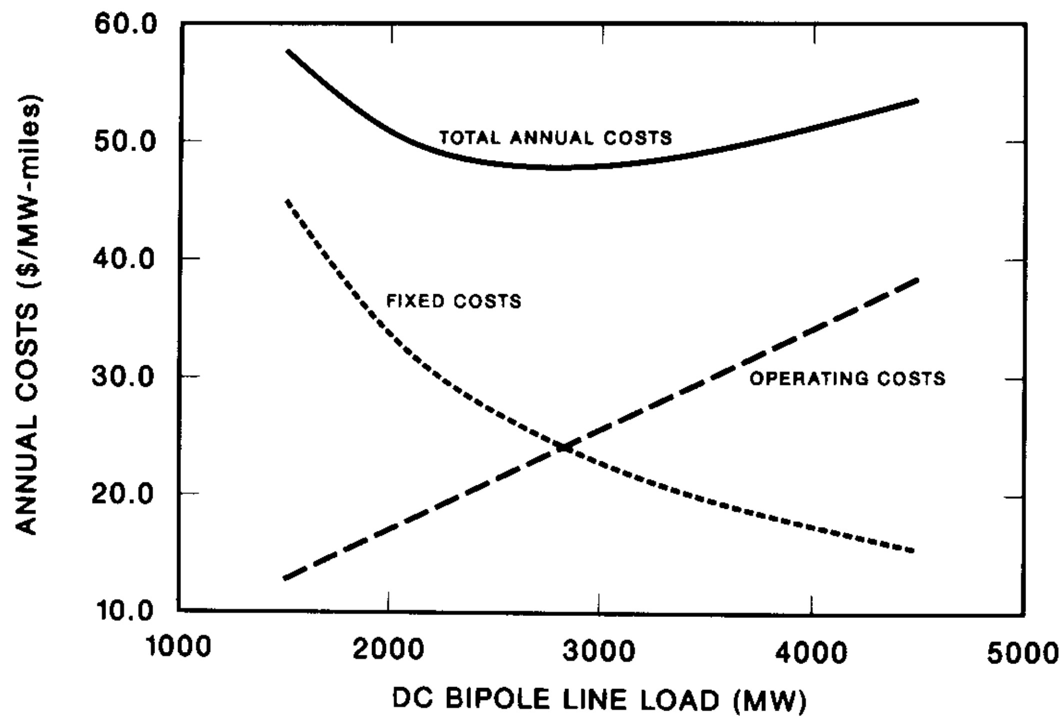

Fig. 10.2. Typical total costs of transmission line, showing fixed, operating, and total annual costs for an 800-kV (±400-kV) dc transmission line.

Construction costs (capital investment) for both ac and dc overhead lines designed to meet commonly accepted criteria are remarkably uniform over wide voltage ranges for the same construction conditions when expressed in dollars per kilovolt-mile. These cost data can be used in determining a number of important economic relationships.

One example using cost estimates from a northwestern utility is illustrated in Fig. 10.3. These estimates are based on typical land costs in the utility's operating region, light steel transmission towers, rolling terrain (versus flat or mountainous), and design for maximum economy.

Costs calculated from this utility's recent estimates range from \$930–\$980/kV-mile for ac voltages from 230 to 765 kV. Corresponding values for dc overhead lines, from ±400 to ±750 kV, are from \$320–\$370/kV-mile. Checks of a few recent transmission projects as reported in the trade journals have yielded kilovolt-mile capital investment costs not greatly different from the foregoing dollar figures. However, similar comparisons may be made by other utilities based on their own engineering design criteria and land cost experience.

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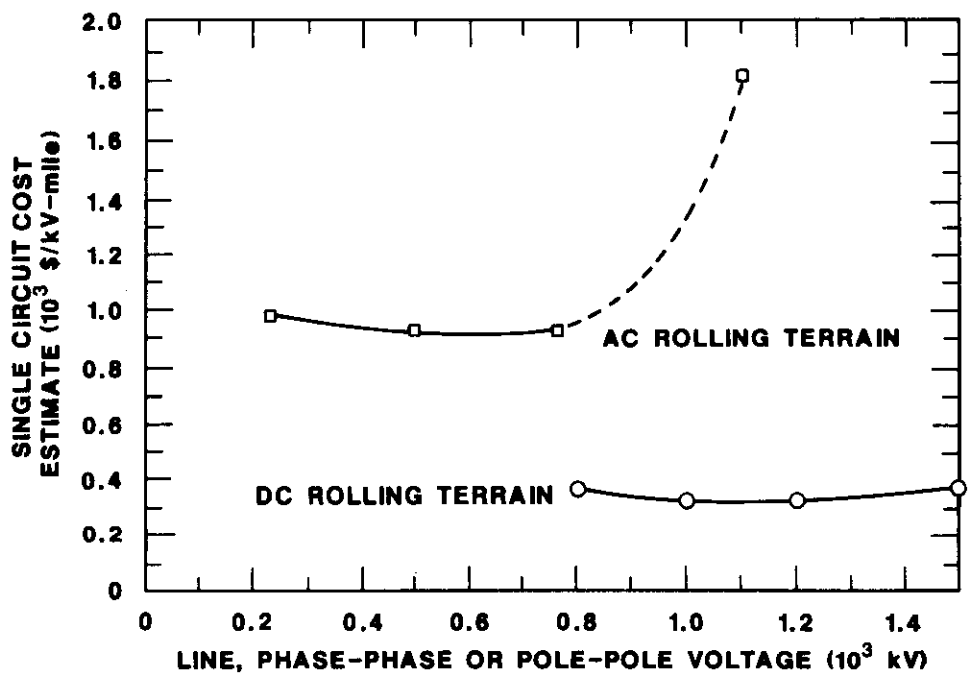

	CONDUCTOR		OHMS/MILE		
230 kV ac –	1 Cowslip	R_a –	0.05670	R_{0a} –	13.0*
500 kV ac –	3 Seahawk		0.02001		10.0
765 kV ac –	4 Thrasher		0.01205		9.2
1100 kV ac –	8 Thrasher		0.00602		6.6
800 kV dc –	2 Seahawk	R_d –	0.02730	R_{0d} –	21.8
1000 kV dc –	2 Thrasher		0.02183		21.8
1200 kV dc –	3 Seahawk		0.01820		21.8
1500 kV dc –	6 Bunting		0.01442		21.6

$*R_{0a} = R_a \cdot kV$ (Equivalent Resistance of a 1.0-kV line)

Fig. 10.3. Typical ac and dc transmission line cost estimates and line resistances per mile. (Estimates are for conditions in the northwestern United States.)

The other part—the annual operating cost—derives primarily from the cost or value of losses. Disregarding corona and leakage current losses, which are relatively small, these are from resistance losses in the line conductors. An examination of typical line resistances discloses important relationships. According to the design criteria followed by the utility mentioned above, the change in power capacity of a line design from an increase in its voltage rating closely follows a square law; the conductor rated current is ordinarily chosen to be at a level proportional to the voltage. Then the phase or pole resistance, when comparing designs for different voltages, is inversely proportional to the design voltage. A resistance relationship can then be developed which is useful when examining the economics of line design over a range of voltages.

If R_0 is defined as the equivalent resistance of a 1-kV line, it is determined by multiplying the actual resistance of the line (per mile) by the voltage (kV) of the line. For the two series of line designs from which data were tabulated in Fig. 10.3, the R_0 values prove to be relatively constant over the 230- to 765-kV ac range, that is, from 13.0 to 9.2 Ω/mile, equivalent resistance of a 1-kV line. For the dc examples, R_0 has values from 21.8 to 21.6 Ω/mile, equivalent resistance of a 1-kV dc line, for the range ± 400 to ± 750 kV.

Several transmission line costs, voltage and load equations based on the above cost, and resistance considerations have been developed (see App. A). From these equations, annual cost, the voltages of minimum annual cost, and line loading for minimum annual cost for ac and dc overhead transmission lines may be estimated.

To illustrate the application of these equations, Figs. 10.4 and 10.5 show the line annual costs per megawatt-mile for transmission of a constant power, 3000 MW, at a constant bipole voltage, ± 500 kV, for loss costs ranging from 11 to 50 mills/kWh. The following section discusses the application of the equations for a preliminary design exploration and the calculation of a dc transmission line economic capacity, annual cost, and cost of losses.

10.3 ECONOMIC COMPARISON OF OVERHEAD LINES

This section gives an economic comparison of dc transmission lines at ± 400 and ± 500 kV. A substantial reduction in line resistance at ± 400 kV at an increased line construction cost but with lower cost converter stations can make the lower voltage design economically and environmentally attractive in comparison with ± 500-kV construction. The higher load levels and loss costs tend to favor the lower voltage if pole resistance is sufficiently reduced.

The lower voltage together with the large conductor bundle reduces corona discharge and thus contributes an environmental advantage. Atmospheric ion production and its contribution to ground-level voltage gradients is substantially reduced.

To illustrate, an approximate total cost comparison for line costs only was made (see Fig. 10.6). The higher voltage line was assumed to use the accepted twin Thrasher conductor of 4624-kcm total cross section with a resistance of 0.02183 Ω/mile. The 400-kV line was assumed to employ a quad-bundle Thrasher of 9248 kcm with a resistance of 0.01092 Ω/mile.[1] Current design estimates indicate that the capital cost for the lower voltage, higher conductance line would be about 40% greater than that for the higher voltage bipole.

However, the total annual costs (or total capitalized costs) at economy loadings are only about 5% greater for the ± 400-kV line. Its right-of-way might be narrower because of reduced electric fields and ion effects in comparison with the ± 500-kV design, and the costs for the lower voltage converter stations should be lower.

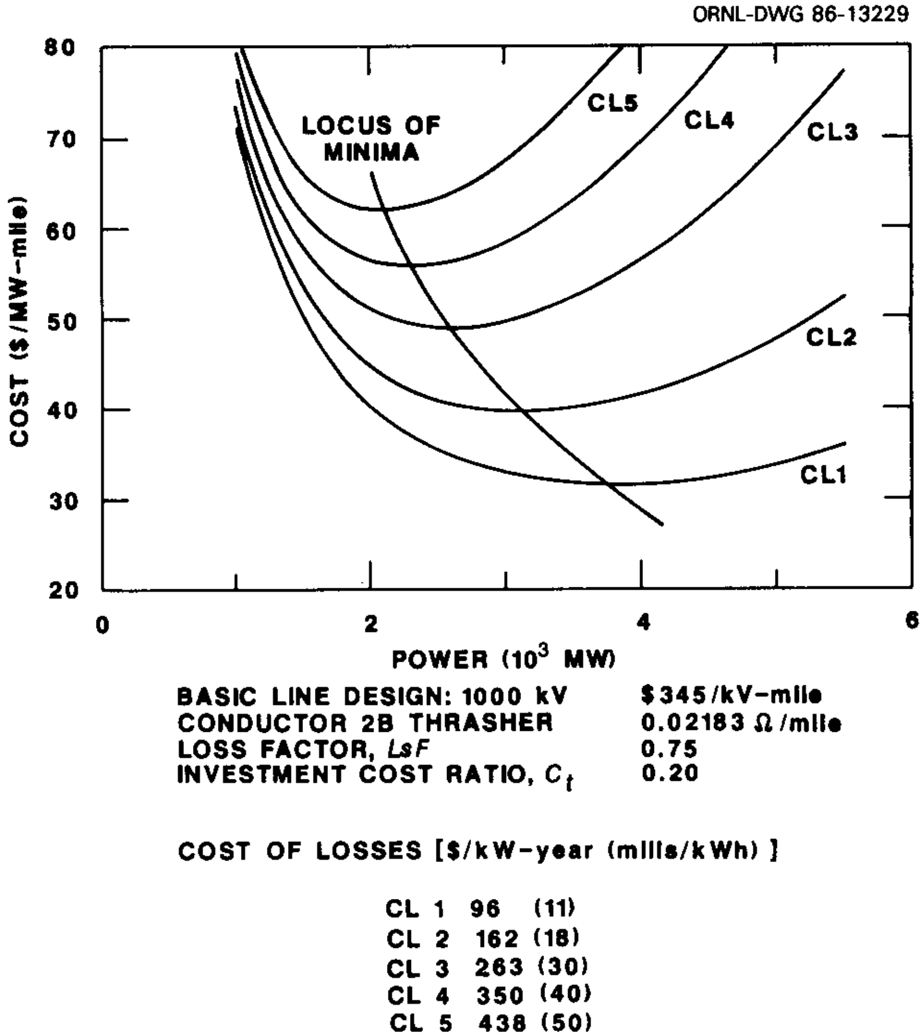

Fig. 10.4. Estimated annual capital costs plus loss costs per megawatt-mile for dc transmission at a fixed bipole voltage of 1000 kV (±500 kV) as a function of the quantity of transmitted power.

Equation A.6 in App. A was used in the calculations for this comparison. The assumptions for these calculations were as follows:

±500 kV, Two-bundle Thrasher	±400 kV, Four-bundle Thrasher
A_d = 320/kV-mile ($321,400/mile)	A_d = 560/kV-mile ($450,000/mile)
C_t = 0.15 (fixed cost ratio)	C_t = 0.15
V_d = 1000 kV	V_d = 800 kV
R_{td} = 0.02183 Ω/mile	R_{td} = 0.01092 Ω/mile
C_L = $300/kW-year (34 mills/kWh)	C_L = $300/kW-year
= $450/kW-year (50 mills/kWh)	= $450/kW-year
= $600/kW-year (68 mills/kWh)	= $600/kW-year
LsF = 0.55 (loss factor)	LsF = 0.55
LF = 0.75 (load factor)	LF = 0.75

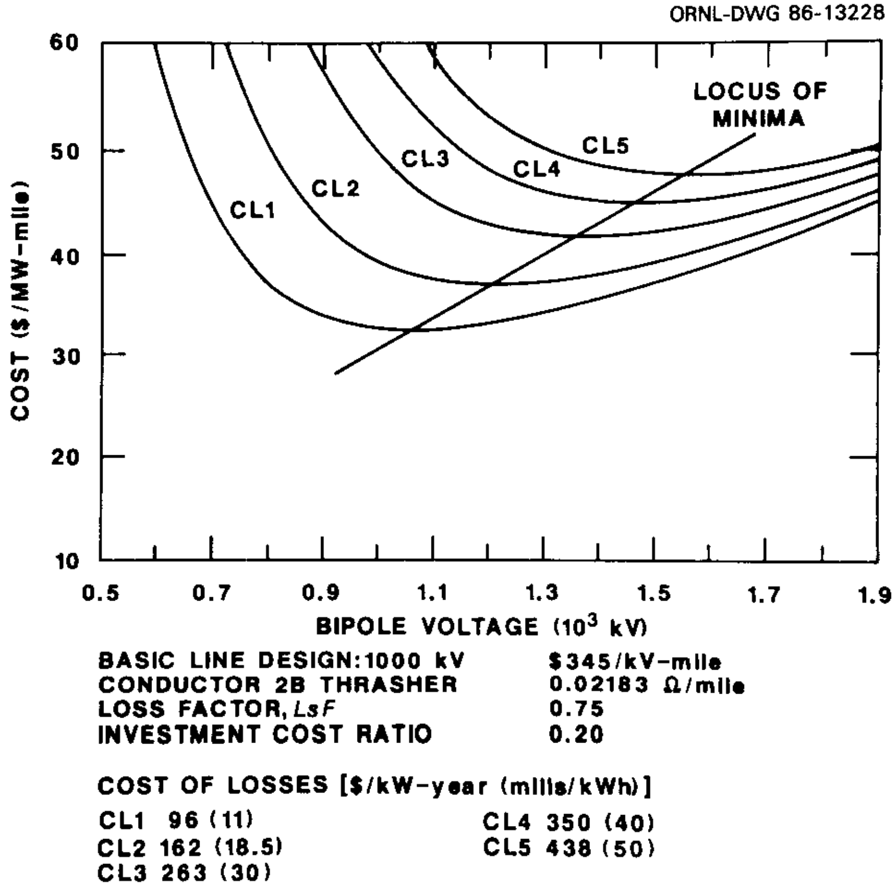

Fig. 10.5. Estimated annual capital costs plus loss costs, in dollars per megawatt-mile, for the line component only for dc transmission at a constant power of 3000 MW plotted as a function of the transmission voltage. (See Eq. A.3 of App. A.)

10.4 UNDERGROUND CABLE COSTS

High-pressure oil-filled pipe-type (HPOPT) cable systems are typically used in the United States. Low-pressure oil-filled (LPOF) cable systems are commonly used in Europe; they also are installed in some applications in the United States. The cost of both HPOPT and LPOF dc underground cable systems is typically less than that of ac underground systems. Direct-current HPOPT cable systems will be slightly less expensive than ac HPOPT systems. The pipe, pumping plant, and installation costs will be nearly identical for either ac or dc systems. The cost of a third conductor for the three-phase ac system will be the major cost difference. However, if a metallic return is needed, then a third conductor will be required for the dc option (although its insulation requirements will be lower). On short transmission lines the costs of cable terminations can become a large percentage of the total cost. Consequently, the reduced number of terminations, (i.e., four on a dc line as compared to the six required for an ac system) will provide a substantial saving for the dc line as compared to the ac line. However, the cost of cable terminations is small when compared to dc converter costs.

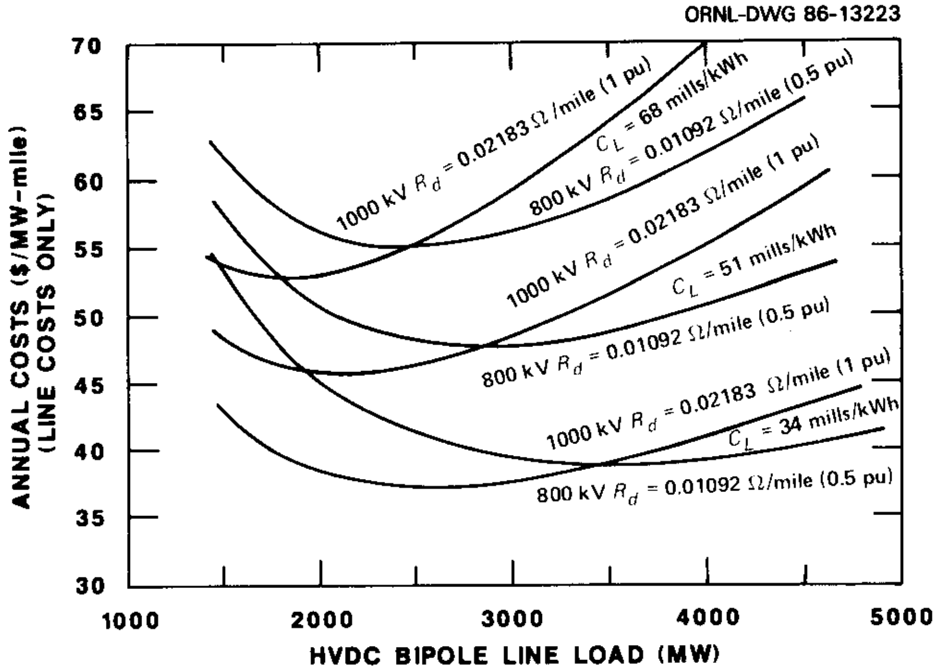

Fig. 10.6. Annual cost comparison of two-bundle Thrasher conductor at 1000 kV (±500 kV) versus four-bundle Thrasher conductor at 800 kV (±400 kV). (Costs of losses are 34, 51, and 68 mills/kWh.)

Components of an underground transmission line cost study should include right-of-way (ROW) clearing and access roads, pipe, manholes, excavation and backfill, cable, insulating oil, terminations, pumping plants, maintenance, and engineering. Material and labor costs for installation items (e.g., pipe welding, cable pulling, splicing, and testing) must be evaluated. Since labor rates and work practices and procedures vary to such a large extent, it is difficult to provide a typical cost for these labor-intensive activities. Material costs are more uniform; however, cable costs do vary as copper and aluminum costs change and also as a function of supply and demand.

Examples of dc underground transmission costs can be found in ref. 2. This study includes evaluations of six different transmission lines with three different route lengths and three current ratings. The evaluation of costs for a 31.4-mile (50-km) ROW from a suburban Philadelphia location to a downtown site is summarized below. This route included 6 miles (9.6 km) of city streets; the remainder was suburban ROW (unpaved). Costs for a ±600-kV HPOPT cable with two poles in one pipe and a rating of 1666 A per pole (1000 MW) (i.e., 2000 MW per pipe) were developed. Note that these costs and the others that follow are for a longer, high-capacity application and that higher costs would prevail in a shorter or lower current system. The average cost per mile of the HPOPT cable over this route was $1.66 million. A self-contained oil-filled (SCOF) cable with the same rating was estimated to cost $2.54 million per mile. A gas-insulated transmission line (GITL) was estimated to cost $6.58 million per mile. However, the rating for the GITL cable was 3000 MW per pole, which is three times the rating of the HPOPT and SCOF designs. In order to achieve this rating, a 10-ft (3-m) separation between poles is necessary to reduce the thermal interference between the cables. System constraints can also reduce the usable rating of a high-capacity transmission line.

For comparison, an underground 500-kV ac GITL line with a 2000-MW rating is $7.57 million per mile. A ±600-kV overhead dc line on the suburban portion of the ROW was estimated to cost $1.75 million per mile; however, this line has a continuous rating of 7520 A (4500 MW) per pole. When the cost for the 6 miles (9.6 km) of city streets that require underground cable is added to the overhead costs, the average cost per mile over the full 31.4 miles (50 km) increases to $4.03 million per mile. Comparison of these costs on the basis of dollars per megavolt-ampere-mile yields the following data: HPOPT—$830; SCOF—$1270; dc GITL—$1096; ac GITL—$3785; dc overhead—$194; and dc overhead (with underground section)—$447.

Material costs for cables in the suburban areas are almost equal to the material costs in city street installations, but the excavation and backfill costs vary greatly between the two areas. For example, the HPOPT excavation and backfill costs are $0.480 million per mile in the suburbs and $1.14 million per mile in the city street portions of the ROW. Note that all of the above costs were developed for one specific application and that these costs cannot be indiscriminately applied to other applications. Unless otherwise noted, they include a mix of suburban and urban costs. Consequently, the averages are higher than those for a suburban private ROW application and less than those for a strictly city street urban ROW. Care must be used in applying costs from one transmission study to other applications since costs are very much site dependent.

10.5 REFERENCES

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2. S. V. Heyer, *Evaluation of Underground DC Transmission Systems, Final Report*, DOE/RA/50158-1, Division of Electric Energy Systems, U.S. DOE, October 1983.

11. CONCLUSIONS

The information in this report is intended to assist electric utility system planners in making economic comparisons between equivalent ac and dc transmission systems. In doing so, it discussed operational characteristics of the two systems, including

- controllability of ac and dc systems,
- asynchronous interconnection using dc,
- power flow modulation by ac and dc systems,
- ac voltage control by ac and dc systems,
- power routing by ac and dc system controls,
- increased power density over a transmission corridor by using dc,
- unchanged ac power flows and short-circuit levels by using dc,
- control of short-circuit impact by using ac techniques, and
- reduced environmental impact in a dc line as compared with an ac line.

For ac systems, information was provided on the use of series and shunt compensation to increase power transmission while retaining stability and acceptable voltage profiles. Examples of sample calculations were provided, together with curves for comparing alternatives.

Data were provided for use in calculating dc converter station costs as a function of power, dc voltage, and ac voltage. Cost data for ac substations, dc and ac transmission lines, and dc underground cables were also presented. Techniques for calculating total costs (including the capitalized costs of losses) were discussed.

Caution must be exercised in comparing the costs of "equivalent" ac and dc systems to be sure that the systems are indeed equivalent in performance. Generic cost information is available in this report to enable the calculation of a "break-even distance" for a simple straightaway energy transport problem. Application of the underlying concepts should be made using estimates for the actual project under consideration. If more than a straightaway energy transport problem is being studied, the incremental additional costs of each performance enhancement of value to the utility should be factored into the comparison to estimate whether the ac or the dc choice is likely to be most profitable.

This report also presented some not-yet-implemented concepts of dc transmission for consideration, with the expectation that a future application may be found. Significant future economic benefits could accrue from these concepts.

Finally, there are probably too many variables and too many constraints to be able to design an "optimum" system. However, if the aim of the system planner is to achieve an economic and reliable design, then the information contained in this report for both dc and ac systems may be of value.

GLOSSARY*

Back-to-back dc system—A dc system in which both converter terminals are in close proximity and bus work serves the transmission function.

Bipolar dc system—A dc system with two poles of opposite polarity.

Bridge—The configuration of valves used to construct a converter.

Commutation—The transfer of current from one valve to another in sequence.

Damping control—A method of dc control in which the transfer power is modulated so as to oppose machine oscillations in the ac system.

DC reactor—An inductor connected in series with the converter on the dc side, primarily to reduce dc current ripple.

Diode converter—A converter constructed of diode valves.

Earth return—The use of the earth as the neutral current return path.

Extinction angle—The time, expressed in electrical degrees, following current extinction in a valve before the appearance of forward bias voltage on that valve. Also called gamma or margin angle.

Firing (of a valve)—The application of gate current to a valve for establishing forward current conduction.

Firing angle—The time, expressed in electrical degrees, between attainment of forward bias of a valve and firing of that valve. Also called alpha or delay angle.

Inverter mode—The converter operating mode in which power is transferred from the dc system to the ac system.

Ion effects—The environmental effects resulting from ions produced by the electrical field of a transmission line.

Metallic return—The use of a metallic conductor as the neutral current return path.

Monopolar dc system—A dc system with only one polarity with respect to earth.

Multiterminal dc system—A dc system with three or more terminals.

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*Some of the entries in this glossary first appeared in the report, *Methodology for Integration of HVDC Links in Large AC Systems—Phase I: Reference Manual,* EL-3004, Electric Power Research Institute, Palo Alto, Calif., March 1983. They are used with permission.

Overlap angle—The time, expressed in electrical degrees, in which two valves involved in a commutation process conduct current simultaneously. Also designated μ or u.

Pole—The parts of a dc system which are electrically connected and have a common direct voltage polarity with respect to earth.

Pulse number—The number of commutations occurring in a converter in one cycle of the ac line voltage. Equal to the number of valves in a dc converter.

Rectifier mode—The converter operating mode in which power is transferred from the ac system to the dc system.

Short-circuit capacity—In per unit, the square of the per-unit operating voltage divided by the per-unit impedance. In megavolt-amperes, the square of the line-to-line voltage divided by the impedance, in ohms. A measure of ac system strength.

Short-circuit ratio—The ratio of ac system short-circuit capacity to dc power transfer level at a converter. A measure of relative ac voltage change and stability caused by converter operation. Values of less than 2.5 are generally regarded as low.

Terminal—The dc installation composed of the converter and its associated ac and dc connections and equipment and auxiliaries.

Thyristor—A bistable semiconductor device comprising three junctions that can be switched from the off-to-on state by the application of gate current.

Valve—A controllable or noncontrollable device capable of conducting current in only one direction when properly biased. Modern dc valves consist of arrays of many thyristors.

Appendix A

TRANSMISSION LINE COST, VOLTAGE, AND LOAD RELATIONSHIPS

INTRODUCTION

When three basic criteria, developed from theory and empirically from design and construction, are recognized, useful estimates of transmission line costs and capacity relationships can be developed. The approximate criteria are as follows:

1. The power capacity of a line is proportional to the square of its operating voltage; that is,

$$P \sim V^2 \ . \qquad \text{(Line current is proportional to the voltage, } I \sim V.\text{)}$$

2. The line resistance for designs of the same class is inversely proportional to the design voltage,

$$R \sim \frac{1}{V} \ . \qquad \text{(Losses are proportional to the voltage, } P \sim V^2.\text{)}$$

3. Line capital cost per mile is approximately proportional to voltage for designs of the same class and general location,

$$C \sim V \ . \qquad \text{(Line cost in dollars per kilovolt-mile is constant, or the total capital cost of a line is approximately proportional to the voltage.)}$$

The following relationships are developed in the next pages:

1. Transmission cost as a function of design voltage (see Eqs. A.1, A.4, A.6, and A.8), given:
   a. Load level, P, kW.
   b. Line cost factor, \$/kV-mile.
   c. Fixed cost ratios, per unit (pu).
   d. Reference design voltage and resistance per phase or per pole.
   e. Cost of losses and annual loss factor.
2. Most economical voltage for given conditions (see Eqs. A.2, A.5, A.7, A.9, A.11, and A.13).
3. Transmission cost per kilowatt-year as function of load (see Eqs. A.14 and A.16), given:
   a. Design voltage, kV (for a specific line).
   b. Design resistance per phase or pole.
   c. Line cost factor, \$/kV-mile.
   d. Fixed cost ratios, per unit (pu).
   e. Cost of losses and annual loss factor.
4. Most economical load for given conditions (see Eqs. A.15 and A.17).
5. Transmission line incremental resistance loss (see Eqs. A.19 and A.20).

MINIMUM-COST TRANSMISSION LINES

Under the foregoing assumed criteria, minimum-cost (either annual or capitalized costs) transmission line (ac or dc) voltages may be determined from the relationships developed in the following sections of this appendix. The annual or capitalized costs each include two significant elements. The annual costs include the annual fixed (investment) cost and the cost of losses. Capitalized costs include total capital investment plus the capitalized value of the losses. For the two options, ac or dc, the transmission distance, power transmitted, and resistance factor R_0 per phase or pole are each assumed constant for any line under study.

Nomenclature

For dc equations in the following developments, use the subscript "d" instead of subscript "a" for ac.

A_a = Total line cost per kilovolt [miles × ($/kV-mile) = $/kV].

A_a' = Line cost, $/kV-mile.

C_a = Capitalized cost of transmission line, $/mile.

C_L = Cost of losses, $/kW-year.

C_t = Capital recovery factor.

C_{tL} = Loss capital cost ratio.

C_{ya} = Total annual cost of transmission line, $/year.

C_{ypa} = Total annual cost per kilowatt, C_y/P.

D = Transmission distance, miles.

D_0 = Break-even distance for equal ac and dc transmission costs, miles.

I_a = Line current per phase or pole, A.

L = Resistive loss, kW.

L_{cap} = Capitalized loss costs, $/kW.

LsF = Loss factor, per unit (pu).

P = Specified capacity (power transmitted), kW.

P_{0a} = Minimum cost load at voltage V_a and R_{ta}, kW.

R_a = Resistance per mile of transmission line phase or pole, Ω/mile.

R_{ta} = Total resistance per phase or pole, R_a × miles, Ω.

R_{0a} = Resistance factor per phase (or pole) of 1.0-kV line, R_{ta} × kV, Ω (design).

R_{0a}' = Resistance factor per mile, R_{0a}/D.

T_{c0} = Terminal cost per kilowatt at reference power level P_0.

V_a = Voltage (line-to-line for ac; bipole for dc), kV.

V_a' = Line-to-line voltage for minimum annual cost at P and constant R_t for each phase or pole, kV.

SUMMARY: AC AND DC SIGNIFICANT RELATIONSHIPS

The following are equations for transmission cost, voltage, and loads derived in this appendix and are presented here for ready reference. They apply only to the line component of the transmission under study.

AC Transmission

Total annual cost—3ϕ ac circuit:

$$C_{ya} = A_a \cdot V_a \cdot C_t + \frac{P^2}{V_a^3} \cdot R_{0a} \cdot C_L(LsF)\,0.001 \quad . \tag{A.1}$$

AC voltage for minimum annual cost, $f(V)$; P (specified), $R \sim 1/V$ (general case):

$$V_a = 0.234\sqrt{P}\left[\frac{R_{0a} \cdot C_L(LsF)}{A_a \cdot C_t}\right]^{0.25} 3\phi \text{ ac voltage, kV.} \tag{A.2}$$

Capitalized loss costs per kilowatt:

$$L_{cap} = \frac{C_L(LsF)}{C_{tL}} \quad \$/\text{kW}. \tag{A.3}$$

Total ac line capital and capitalized loss costs:

$$C_a = A_a \cdot V_a + \frac{P^2}{(V_a)^3} \cdot R_{0a} \cdot L_{cap} \cdot 0.001 \quad . \tag{A.4}$$

Optimum ac voltage at a given power level, function of L_{cap}:

$$V = 0.234\sqrt{P}\left[\frac{R_{0a}}{A_a} \cdot L_{cap}\right]^{0.25} \phi\text{–}\phi \text{ kV, ac} \quad . \tag{A.5}$$

AC line load level for minimum cost per kilowatt-year or loading of maximum economy at ac ϕ–ϕ voltage, V_a, and resistance per phase, R_{ta}, $f(P)$:

$$P_{0a} = 31.6\, V_a^{3/2}\left[\frac{A_a \cdot C_t}{R_{ta} \cdot C_L \cdot (LsF)}\right]^{0.5} \tag{A.15}$$

= kilowatt load for minimum cost per kilowatt-year or maximum economy loading at ϕ–ϕ line voltage V_a and total phase resistance R_{ta}.

DC Transmission

Total annual cost—bipole dc:

$$C_{yd} = A_d \cdot V_d \cdot C_t + 2\frac{P^2}{(V_d)^3} \cdot R_{0d} \cdot C_L \cdot (LsF) \cdot 0.001 \ . \tag{A.6}$$

DC voltage for minimum annual cost, $f(\text{kV})$; P (specified), $R \sim 1/V$ (general case):

$$V_d = 0.278\sqrt{P}\left[\frac{R_{0d} \cdot C_L \cdot (LsF)}{A_d C_t}\right]^{0.25} \text{bipole dc voltage} \ . \tag{A.7}$$

Total dc line capital and capitalized loss costs:

$$C_d = A_d \cdot V_d + 2\,\frac{P^2}{(V_d)^3} \cdot R_{0d} \cdot L_{cap} \cdot 0.001 \ . \tag{A.8}$$

Optimum dc voltage at a given power level, function of L_{cap}:

$$V_d = 0.268\sqrt{P}\left[\frac{R_{0d}}{A_d} \cdot L_{cap}\right]^{0.25} \text{bipole kV, dc} \ . \tag{A.9}$$

DC line load level for minimum cost per kilowatt-year or loading of maximum economy at bipole voltage, V_d, and total pole resistance R_{td}, $f(P)$.

$$P_{0d} = 22.36\, V_d^{3/2}\left[\frac{A_d \cdot C_t}{R_{td} \cdot C_L \cdot (LsF)}\right]^{0.5} \tag{A.17}$$

= kilowatt load for minimum cost per kilowatt-year or maximum economy loading at bipole voltage V_d and total pole resistance R_{td}.

MINIMUM-COST AC TRANSMISSION VOLTAGE—LINE COMPONENT ONLY

Minimum Annual Cost

The significant components of annual costs include the annual fixed charges for the capital investment and the annual cost of losses. O&M charges are assumed to be approximately equal for the two technologies, ac and dc, and are neglected in the following developments. First, with P in kilowatts and V in kilovolts, calculate the ac line resistance loss:

$$I_a = \frac{P}{\sqrt{3}V_a}\ \text{A}$$

$$3I_a^2 = \frac{P^2}{V_a^2} \ .$$

The 3ϕ resistance loss, L, is

$$L_a = \frac{3I_a^2 R_{ta}}{1000} \text{ kW} .$$

Annual cost for the ac line:

$$C_{ya} = (A_a)(V_a)(C_t) + 3(I_a^2)(R_{ta})(C_L)(LsF)(0.001) = f(V_a) ,$$

$$C_{ya} = (A_a)(V_a)(C_t) + \left(\frac{P}{V_a}\right)^2 \cdot \frac{R_{0a}}{V_a} \cdot C_L \cdot (LsF) \cdot 0.001 ,$$

or

$$C_{ya} = A_a \cdot V_a \cdot C_t + \frac{P^2}{V_a^3} \cdot R_{0a} \cdot C_L \cdot (LsF) \cdot 0.001\$/\text{yr} . \tag{A.1}$$

Minimum-cost relationships are determined for this equation by taking the first derivative of C_{ya} with respect to V_a and setting it equal to zero.

$$\frac{dC_{ya}}{dV_a} = A_a \cdot C_t - 3\frac{P^2}{(V_a)^4} \cdot R_{0a} \cdot C_L \cdot (LsF) \cdot 0.001 = 0 .$$

Then, for minimum annual cost,

$$A_a C_t = 3\frac{P^2}{(V_a)^4} R_{0a} \cdot C_L \cdot (LsF) \cdot 0.001$$

or

$$V_a = \left[3\frac{P^2}{A_a C_t} \cdot R_{0a} \cdot C_L \cdot (LsF) \cdot 0.001\right]^{0.25}$$

$$= \sqrt{P}\left[3 \cdot \frac{R_{0a} C_L}{A_a C_t} \cdot (LsF) \cdot 0.001\right]^{0.25} .$$

The ac voltage, then, for minimum annual cost for constant P (kW) design capacity over a fixed transmission distance and for R_{0a}, the equivalent resistance of a 1-kV ac line of that length, is

$$V_a = 0.234 \cdot \sqrt{P}\left[\frac{R_{0a} \cdot C_L \cdot (LsF)}{A_a \cdot C_t}\right]^{0.25} \tag{A.2}$$

= ac line voltage, ϕ–ϕ, kV, for minimum cost .

Example. Let $P = 2.0$, $R_{0a} = 0.50$, and $A_a = 1.3$ pu or relative values, the other factors remaining unchanged; then

$$V_a = 1.1135 ;$$

that is, about an 11.4% voltage increase would be required for minimum cost at 2× power transmitted with 50% less line resistance and 30% line construction cost increase.

Capitalized Cost of AC Transmission Lines

The equivalent capital cost of an ac transmission line would include the plant investment plus the capitalized value of losses. The capitalized loss costs, L_{cap}, are

$$L_{cap} = \frac{C_L \cdot LsF}{C_{tL}} \quad . \tag{A.3}$$

Example: Let C_L = \$440/kW-year loss at 100% load factor, $LsF = 0.75$, and $C_{tL} = 0.17$. Then

$$L_{cap} = \frac{(\$440)(0.75)}{(0.17)} = \$1941/\text{kW of losses} \quad .$$

To calculate the equivalent capital cost for a transmission line, take its direct capital investment plus the capitalized value of losses, all in dollars/mile.

AC (see Eq. A.1):

$$C_a = A_a' \cdot V_a + \frac{P^2}{(V_a)^3} \cdot R_{0a'} \cdot L_{cap} \cdot 0.001\,\$/\text{mile} \quad . \tag{A.4}$$

The optimum voltage at a given power level, P (kW), as a function of the capitalized loss cost per kilowatt, L_{cap}:

AC (see Eq. A.2):

$$V_a = 0.234\sqrt{P}\left[\frac{R_{0a'}}{A_a'} \cdot L_{cap}\right]^{0.25} \phi\text{–}\phi\ \text{kV, ac} \quad . \tag{A.5}$$

MINIMUM-COST DC TRANSMISSION VOLTAGE—LINE COMPONENT ONLY

Minimum Annual Cost

Under the same general assumptions as for ac transmission, the following relationships may be developed. These calculations include the annual fixed investment cost and the annual cost of losses. The transmission distance, power transmitted, and the total resistance per pole are each assumed constant for any dc line under study. First, with pole-to-pole voltage in kilovolts, calculate the dc line resistance loss:

$$I_d^2 = \left(\frac{P}{V_d}\right)^2 \quad .$$

The dc bipole resistance loss, L, is

$$L = \frac{2I_d^2 R_{td}}{1000} \text{ bipole dc kW loss} \quad .$$

The annual cost for the dc line:

$$C_{yd} = (A_d)(V_d)(C_t) + 2(I_d^2)(R_{td})(C_L)(LsF)(0.001) = f(V_d)\$/\text{year} \ .$$

The total annual cost for a dc transmission line, for constant power levels, as a function of the pole-to-pole (bipolar) voltage—$f(V_d)$:

$$C_{yd} = (A_d)(V_d)(C_t) + 2\left[\frac{P}{V_d}\right]^2 \frac{R_{0d}}{V_d} C_L \cdot (LsF) \cdot 0.001$$

or

$$C_{yd} = A_d \cdot V_d \cdot C_t + 2\frac{P^2}{V_d^3} \cdot R_{0d} \cdot C_L \cdot (LsF) \cdot 0.001 \ . \tag{A.6}$$

The minimum-cost relationships are determined for this equation by taking the first derivative of C_{yd} with respect to V_d and setting it equal to zero:

$$\frac{dC_{yd}}{dV_d} = A_d \cdot C_t - 6\frac{P^2}{V_d^4} R_{0d} \cdot C_L \cdot (LsF) \cdot 0.001 = 0 \ .$$

Then, for minimum annual cost,

$$A_d C_t = 6\frac{P^2}{V_d^4} \cdot R_{0d} \cdot C_L \cdot (LsF) \cdot 0.001$$

or the bipole voltage for least annual cost,

$$V_d = \left[6 \cdot \frac{P^2}{A_d C_t} \cdot R_{0d} \cdot C_L \cdot (LsF) \cdot 0.001\right]^{0.25}$$

$$= 0.278\sqrt{P}\left[\frac{R_{0d}}{A_d} \cdot \frac{C_L}{C_t} \cdot (LsF)\right]^{0.25} \text{kV} \tag{A.7}$$

= bipolar line voltage, pole-to-pole, for minimum annual cost, line only, at P (kW) design capacity .

Example: Let P, R_{0d}, A_d, and LsF = 1.0 pu and C_L = 2.0 pu. Then,

$$V_d = \sqrt[4]{2} = 1.189 \text{ pu} \ ,$$

or about a 19% voltage increase will be required for minimum cost at 2× loss cost evaluation, with other factors unchanged.

Capitalized Cost of DC Transmission Lines

Using similar procedures as for ac line capitalized costs, take the dc line direct capital cost plus the capitalized value of losses (see Eq. A.3), all in dollars/mile:

$$C_d = A_d' \cdot V_d + 2\frac{P^2}{(V_d)^3} \cdot R_{0d}' \cdot L_{cap} \cdot 0.001\,\$/\text{mile} \ . \tag{A.8}$$

The optimum dc voltage at a given power level, P (kW), as a function of the capitalized loss cost per kilowatt, L_{cap} is:

DC:

$$V_d = 0.278\sqrt{P}\left[\frac{R_{0d}'}{A_d'} L_{cap}\right]^{0.25} \text{bipole kV, dc} \ . \tag{A.9}$$

OTHER MINIMUM ANNUAL COST RELATIONSHIPS: SPECIFIC LINES AND SPECIFIC CONDUCTORS

AC Case—$f(V_a)$

Determine the line-to-line ac voltage in kilovolts for minimum annual cost, given power, P (kW), and a fixed total resistance, R_{ta}, per phase. This is for *specific conductors.*

$$C_{ya}' = A_a \cdot V_a \cdot C_t + \frac{P^2}{V_a^2} \cdot R_{ta} \cdot C_L \cdot (LsF) \cdot 0.001 \ . \tag{A.10}$$

Take the derivative of C_{ya}' with respect to V_a, set it equal to zero, and then determine the ac voltage:

$$V_a' = 0.126\,P^{2/3}\left[\frac{R_{ta} \cdot C_L \cdot (LsF)}{A_a \cdot C_t}\right]^{1/3} \text{kV} \tag{A.11}$$

$=$ ϕ–ϕ ac voltage for minimum annual cost at P (kW) and R_{ta} constant for each phase conductor of the line.

DC Case—$f(V_d)$

Determine the bipole voltage V_d (kV) for minimum annual cost, given power P (kW) and a fixed resistance, R_{td}, per pole. This is for *specific conductors.*

$$C_{yd} = A_d \cdot C_t \cdot V_d + 2\left(\frac{P}{V_d}\right)^2 \cdot R_{td} \cdot C_L \cdot (LsF) \cdot 0.001\,\$/\text{year} \ . \tag{A.12}$$

Take the derivative of C_{yd}' with respect to V_d, set it equal to zero, and then determine the bipole voltage:

$$V_d = 0.159\, P^{2/3} \left[\frac{R_{td} \cdot C_L \cdot (LsF)}{A_d \cdot C_t}\right]^{1/3} \text{kV} \tag{A.13}$$

= bipole voltage for minimum annual cost at P (kW) and R_{td} constant for each pole of the transmission line.

AC Case—*f*(*P*)

Determine the kilowatt load P for minimum cost per kilowatt-year at a given ac voltage V_a, and total line resistance, R_{ta}, per conductor for a *specific line*. Divide Eq. A.1 by the power P and substitute R_{ta} for R_{0a}/V_a:

$$C_{ypa} = \frac{A_a \cdot C_t \cdot V_a}{P} + \frac{P}{V_a^2} \cdot R_{ta} \cdot C_L \cdot (LsF) \cdot 0.001\ \$/\text{kW-year}\ . \tag{A.14}$$

Then take its derivative with respect to P and set it equal to zero to permit determination of the kilowatt load for the minimum cost per kilowatt-year:

$$P_{0a} = 31.6\, V_a^{3/2} \left[\frac{A_a \cdot C_t}{R_{ta} \cdot C_L \cdot (LsF)}\right]^{0.5} \text{kW} \tag{A.15}$$

= kilowatt load for minimum cost per kilowatt-year at ϕ–ϕ line voltage V_a and total phase resistance R_{ta}.

DC Case—*f*(*P*)

Determine the kilowatt load for the minimum cost per kilowatt-year at a given bipole voltage V_d and dc line resistance R_{td} for a *specific line*. Divide Eq. A.6, annual cost (C_{yd}') by the power P to obtain the cost per kilowatt-year:

$$C_{ypd} = \frac{A_d \cdot C_t \cdot V_d}{P} + 2 \cdot \frac{P}{V_d^2} \cdot R_{td} \cdot C_L \cdot (LsF) \cdot 0.001\ . \tag{A.16}$$

Take the derivative of C_{ypd}' with respect to P and set it equal to zero to permit determination of the kilowatt load for minimum cost per kilowatt-year:

$$P_{0d} = 22.36\, V_d^{3/2} \left[\frac{A_d \cdot C_t}{R_{td} \cdot C_L \cdot (LsF)}\right]^{0.5} \text{kW} \tag{A.17}$$

= kilowatt load for minimum cost per kilowatt-year at bipole voltage V_d and total pole resistance R_{td}.

Equation A.15 can be restated for the more general case where $R_{ta} = R_{0a}/V_a$ and substituting L_{cap} for $C_L(LsF)/C_t$:

AC:

$$P_{0a} = 31.6\, V^2 \left[\frac{A_a}{R_{0a} \cdot L_{cap}} \right]^{0.5} . \tag{A.15a}$$

For the similar dc case, Eq. A.17 can be expanded to the more general case where the dc pole resistance $R_{td} = R_{0d}/V_d$ and substituting L_{cap} for the same factors as above:

DC:

$$P_{0d} = 22.36\, V^2 \left[\frac{A_d}{R_{0d} \cdot L_{cap}} \right]^{0.5} , \tag{A.17a}$$

or, solving for voltage in Eq. A.17a,

$$V = 0.2115 \sqrt{P_{0d}} \left[\frac{R_{0d} \cdot C_L \cdot (LsF)}{A_d \cdot C_t} \right]^{0.25} \text{ kV,} \tag{A.17b}$$

where V_1 is the specific voltage at which P_{0d} is the most economical load, $f(P)$ at V_1, for the system constants chosen. It is *NOT* the most economical voltage for the specific P_{0d}, $f(V)$ at P_{0d} (see Eq. A.7).

AC–DC HIGH-VOLTAGE TRANSMISSION COST BREAK-EVEN DISTANCE—D_0

The direct costs of a specific transmission project become equal for high-voltage ac and dc when the dc line cost saving in comparison with the cost of the ac line is equal to the difference between the dc and ac terminal costs. The transmission distance for which the foregoing relationships are true is known as the transmission break-even distance. An approximate expression for the break-even distance can be obtained by the application of certain assumptions previously justified. In the following analysis, let

K_1 = cost per kilovolt-mile of ac lines, including capitalized losses at power level, P, and at optimum voltage, V.

K_2 = ratio of dc to ac line costs (K_1) for the same conditions and power level at the most economic dc voltage.

K_3 = $\dfrac{P}{V^2}$ (i.e., $P = \dfrac{V^2}{X_t} \sin\delta$, or $K_3 = \dfrac{\sin\delta}{X_t}$.

K_4, K_5 = terminal costs per kilowatt, ac and dc respectively, two terminals each, including capitalized losses, at voltages indicated.

a, $b1$, $b2$ = appropriate exponents: $a > 1.0$ for distances greater than 250 miles to account for required ac reactive compensation; $b1$ and $b2 < 1.0$; all obtained from design experience.

Line costs, including capitalized losses, are

$$AC_L = K_1\, VD^a \text{ at optimum ac voltage ,}$$

$$DC_L = K_2 K_1 VD \text{ at most economic dc voltage ,}$$

$$P = K_3 V^2 \text{ ac power level rating, kW ,}$$

$$V = \left[\frac{P}{K_3}\right]^{0.5} \text{kV ac .}$$

The line cost difference is

$$\Delta C_L = K_1 \left(\frac{P}{K_3}\right)^{0.5} (D^a - K_2 D) \ .$$

The terminal costs, including capitalized losses, are

$$AC_t = K_4 P^{b1}$$

$$DC_t = K_5 P^{b2} \ ,$$

and the terminal cost difference is

$$\Delta C_t = K_5 P^{b2} - K_4 P^{b1} \ .$$

Then, for break-even distance D_0,

$$\Delta C_L = \Delta C_t$$

or

$$K_1 \left(\frac{P}{K_3}\right)^{0.5} (D_0^a - K_2 D_0) = K_5 P^{b2} - K_4 P^{b1} \ . \tag{A.18}$$

For the base case, assuming unity exponents,

$$a = b1 = b2 = 1.0 \ .$$

Then, from Eq. A.18,

$$D_0(1 - K_2) = \frac{P(K_5 - K_4)K_3^{0.5}}{K_1 P^{0.5}} \tag{A.19}$$

and

$$D_0 = P^{0.5} \frac{(K_5 - K_4)K_3^{0.5}}{K_1(1 - K_2)} \tag{A.20}$$

$$= K_0 P^{0.5} \text{miles for } V \approx \sqrt{P} \ , \tag{A.21}$$

where

$$K_0 = \frac{(K_5 - K_4)K_3^{0.5}}{K_1(1 - K_2)} \quad . \tag{A.22}$$

The value of the exponents, a, $b1$, and $b2$, obtained from experience, are such that, more realistically, the break-even distance will be in the following range:

$$D_0 \approx K_0 P^{0.2} \text{ to } K_0 P^{0.3} \quad . \tag{A.23}$$

For example, if the cost of the ac line compensation is included in the term K_1 of Eq. A.22, the value of K_0 will be decreased perhaps 5–10% to K_0' and if the exponents $b1$ and $b2$ of Eq. A.18 are each set at 0.8, then Eq. A.21 becomes

$$D_0' = K_0' P^{0.3} \text{ miles} \quad . \tag{A.24}$$

Examination of the above approximate comparative-distance expressions shows, in general, that high power levels require greater direct cost break-even distances than do lower power levels, which may be found to be more competitive than has at first been commonly assumed.

It is interesting to observe that series capacitor compensation of the ac line under consideration increases the value of K_3 by reducing the line net reactance, X_t, thereby increasing the break-even distance D_0. However, series compensation increases the value of K_1, thereby offsetting to some extent the effect of the increase in K_3 in Eqs. A.20 and A.22.

Note that the term $(K_5 - K_4)$ in Eqs. A.19, A.20, and A.22 is the difference in terminal costs per kilowatt between dc and ac, including capitalized losses at the reference power level, P_0, and corresponding voltages. This cost difference is a function of power level and operating voltages and is evaluated in the following analysis:

If the terminal cost, T_c, at design power level P is $T_c = K_t P^b$ (\$),

$$K_t = \frac{T_{c0}}{P_0^b} \, , \tag{A.25}$$

where T_{co} is the terminal cost at the reference power level, P_0; and the terminal cost at the design power level P may be expressed as

$$T_c = \frac{T_{c0}}{P_0^b} P^b \, (\$). \tag{A.26}$$

The terminal cost per kilowatt at the reference power level P_0 is

$$T_{c0}' = \frac{K_t P_0^b}{P_0} = K_t \, P_0^{(b-1)} \, , \tag{A.27}$$

and the unit cost at any higher or lower design power level P is

$$T_c' = \frac{K_t P^b}{P} = K_t \, P_0^{(b-1)} \, ; \tag{A.28}$$

therefore, the value of $\frac{T_c'}{T_{c0}'}$ is $\left[\frac{P}{P_0}\right]^{(b-1)}$

This is the terminal cost difference modifier for Eq. A.20, which can be expanded to

$$D_0 = P^{0.5}\frac{(K_5 - K_4)K_3^{0.5}}{K_1(1 - K_2)} \cdot \left[\frac{P}{P_0}\right]^{(b-1)} \text{ miles}, \tag{A.29}$$

and if ΔC is the per-unit increment for ac line reactive compensation requirements,

$$D_0 = P^{0.5}\frac{(K_5 - K_4)K_3^{0.5}}{K_1(1 + \Delta C - K_2)} \cdot \left[\frac{P}{P_0}\right]^{(b-1)} . \tag{A.30}$$

Thus, if $P/P_0 = 4$ and $b = 0.85$, for example, the \$/kW at design power level P would be about 81% of its value at the reference power level P. Similarly, if $P/P_0 = 0.25$ and $b = 0.85$, the \$/kW at power level P would be about 123% of its value at the reference power level P.

An approximate solution for the cost break-even distance estimates may be used for general evaluation of a straightaway energy transport problem:

$$\Delta T_c = K_t P^b \tag{A.31}$$

$$\Delta L_c = DK_L V = DK_L K_P P^{0.5} \tag{A.32}$$

$$V = K_P P^{0.5} \tag{A.33}$$

$$\frac{\Delta T_c}{\Delta L_c} = \frac{K_t P^b}{DK_L K_P P^{0.5}} = \frac{K_x P^{(b-0.5)}}{D} = 1.0 \text{ for break-even distance}$$

or

$$D_0 = K_x P^{(b-0.5)} \text{, the direct cost break-even distance,} \tag{A.34}$$

where

ΔT_c = dc-ac terminal cost difference at design power level P in kW,
ΔL_c = ac-dc line cost difference at voltage V,
P = kilowatts transmitted,
D = transmission distance in miles,
V = transmission voltage in kV,
b = power level cost exponent (<1.0),
K_x = $K_t/(K_L K_p)$.

Appendix B

AC TRANSMISSION COMPENSATION CALCULATIONS

INTRODUCTION

Alternating-current power transmission performance, both technically and economically, is affected substantially by reactive as well as active power flow. In general, the most satisfactory operational performance occurs at or near the "surge impedance" or natural load level. At this level the reactive power lost in the line series inductive reactance due to current flow is balanced by the line shunt capacitance, and there is no reactive power flow at either terminal. Except for resistance effects, which are minor in EHV ac lines, the longitudinal voltage profile is essentially flat.

The natural surge impedance and corresponding load level can be adjusted up or down by shunt or series capacitive and inductive reactances, as shown in Fig. 5.2. In general, shunt reactance in a given circuit controls the voltage level, and series reactance controls load angle, both of which are critical to load flow and stability. To achieve the best performance and economy, a long transmission circuit may require both series and shunt capacitive compensation at full load and shunt inductive compensation at light or no load. For instance, as shown in Fig. 5.2, a 50% series and 100% shunt capacitive compensated line has an adjusted surge impedance load (SIL) level that is twice its uncompensated value; and the load angle, δ, is the same as for the uncompensated SIL case. At no load, however, the curves indicate the need for 100% total shunt inductive compensation if the voltage profile is held flat, with no reactive power flow at either terminal.

This condition is seldom imposed. A 5% no-load voltage rise is commonly accepted; depending on the line length and degree of series compensation, less than 75% shunt inductive compensation is usually required. In a typical case, a 300-mile 75% series compensated 525-kV line would require no load-rejection shunt reactors to hold the voltage rise, receiving end over sending end, to a reasonable limit, that is, to about 5%.

With lesser degrees of series compensation in long transmission circuits, shunt reactors are often needed to limit light and no-load overvoltages. For example, for a 300-mile 50% series compensated line, about 25% (of the total line-charging kVA) shunt inductive kVA would be required at the receiving terminal to limit the line voltage rise to about 5%. Without series compensation, about 40% shunt reactive would be needed.

Analysis of the basic transmission relationships shows that net inductive shunt compensation reduces the adjusted SIL. Hence, such compensation should be switchable or otherwise controllable under heavy load conditions.

The following examples illustrate the approximate reactive power compensation required to permit transmission loadings other than those for uncompensated operation. The calculation results are within 5% of the exact values; thus, they are adequate for preliminary design estimating purposes.

Calculations of the steady-state performance of a balanced three-phase circuit may be made on a single-phase basis using the phase-to-neutral voltage and the phase values of currents and impedances. Alternatively, the per-unit system may be used for the calculations.

Per-Unit Relationships

The per-unit value of any electrical quantity, such as voltage, power, impedance, or current, is the ratio of the quantity to its base value, the ratio being expressed as a decimal. Any two of the foregoing unit or base values must be known. For example, assume that the phase-to-phase voltage of 525 kV is the unit, or base, voltage and that the base impedance is 280 Ω, corresponding to the square root of the product of the line's series inductive reactance, X_L, and its shunt capacitive reactance, X_C. The other two base quantities may then be readily calculated. From the fundamental electrical relationships between the four quantities in a three-phase circuit and given the two base quantities noted, the base, or unit, power is 984 MW; and the base, or unit, current is 1083 A.

Percent Compensation

The amount of compensation is often expressed as a percentage. For example, percent shunt compensation would be the compensation expressed as a percentage of the line's total shunt capacitive reactance, while the percent series compensation would be the percentage of the line's total series inductive reactance.

Nomenclature

P_n = Natural or adjusted surge impedance power.
P_{n0} = Uncompensated surge impedance power.
SIL = Surge impedance loading or natural power of a circuit.
R = Line resistance of a circuit, Ω.
D = Transmission distance, miles.
X_{L1} = Circuit series inductive reactance per mile, Ω/mile.
X_L = Circuit series inductive reactance, Ω.
X_{C1} = Circuit shunt capacitive reactance, Ω-miles.
X_C = Circuit shunt capacitive reactance, Ω.
B_C = Circuit shunt capacitive susceptance, mhos.
ΔX_C = Compensating shunt capacitive reactance, Ω.
ΔX_L = Compensating shunt inductive reactance, Ω.
X_{se} = Compensating series capacitor reactance, Ω.
X_{LC} = Series compensated line, total net reactance, Ω.
X_{CC} = Shunt compensated line, total shunt reactance, Ω.
ΔMVA_{sh} = Compensating shunt reactive power, MVA.
MVA_{se} = Compensating series capacitor reactive power, MVA.
MVA_{cc} = Compensated circuit total shunt capacitive, MVA.
δ = Circuit voltage displacement angle, degrees at P_n.
δ_0 = Circuit voltage displacement angle, degrees at P_{n0} (uncompensated).
Z_0 = Uncompensated surge impedance, Ω.
Z_{0c} = Natural (adjusted) surge impedance, Ω.
E = Voltage, kV (subscript "R" for receiving end and subscript "S" for sending end of transmission).
n = Ratio of sending- to receiving-end voltages.
I_p = Active load current—assumed unity power factor load.

I_c = Total line or line section charging current—uncompensated.
ΔI_{cR} = Receiving terminal shunt compensating charging current.
pu = Per-unit quantity—relative to base voltage, power, current, or impedance.

EXAMPLE B.1—CALCULATION OF COMPENSATION REQUIREMENTS—2× SIL

This example demonstrates the calculation of series and shunt compensation for a 525-kV, 300-mile, triple Chukar transmission line that is to be loaded to twice its uncompensated SIL. Assumptions for this example include (1) a maximum steady-state load angle, δ, of 35° at unity power factor load, (2) a receiving-end voltage of 525 kV, and (3) a sending-end voltage that is 103% of the receiving voltage. (See Fig. B.1 for phasor analysis of this example.)

Calculations, using the foregoing equations, will be based on equivalent π transmission line impedances. Reference 1, Fig. 6, gives 0.94 for the line series inductance and 0.97 for its shunt

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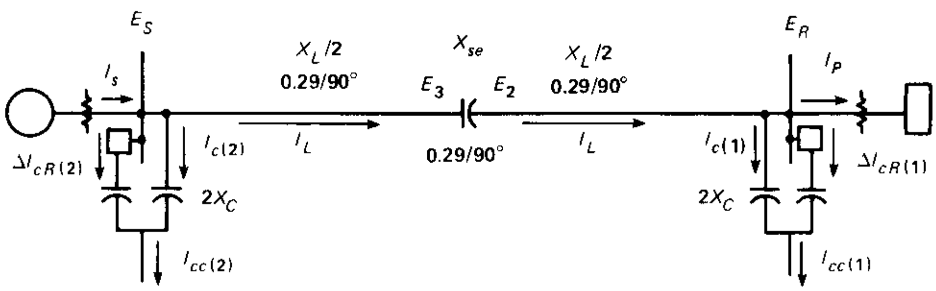
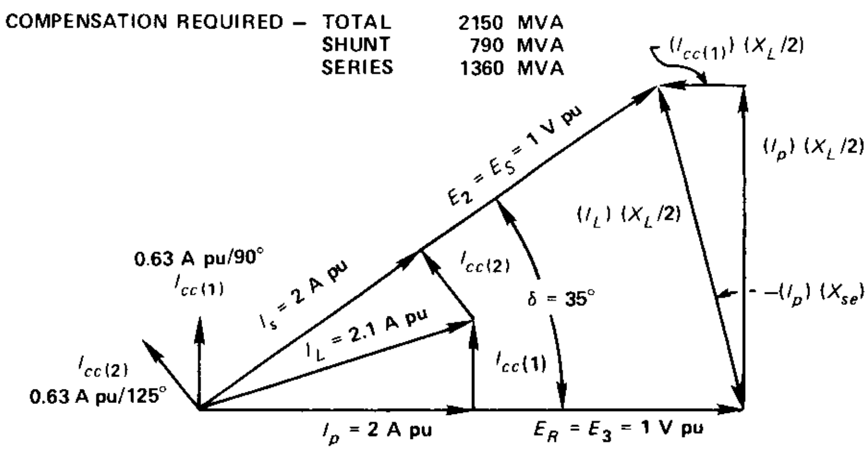


(a) ONE-LINE DIAGRAM OF TRANSMISSION SYSTEM. DISTANCE EQUALS 300 MILES.



(b) PHASOR DIAGRAM FOR ABOVE TRANSMISSION WITH LOADING AT TWICE ITS UNCOMPENSATED SIL. THIS PHASOR DIAGRAM APPLIES EQUALLY WELL TO AN UNCOMPENSATED LINE AT P_n = 1 pu, THAT IS, I_p = 1.0 pu, $I_{c(1)}$ = 0.318 A pu, AND X_L = 0.58 Ω pu.

Fig. B.1. Approximate phasor analysis of a series- and shunt-compensated 525-kV transmission line. (Resistance neglected—$X/R \approx$ 25–30.)

capacitance. These factors are applied to the impedance elements of the transmission nominal π impedances.

Line Impedance and Per-Unit Base Quantities

$R = 0.02\ \Omega$/mile; $X_{L1} = 0.53\ \Omega$/mile; $X_{C1} = 125{,}000\ \Omega$-mile; $D = 300$ miles.

$P = 2$ pu at $\delta = 35°$.

$$\begin{aligned}\text{Base Power: } P_{n0} &= E^2/Z_0\,\text{MW}\\ &= 525^2/\sqrt{(0.53)(125{,}000)}\\ &= 525^2/257.4\\ &= 1071\ \text{MW} = 1\ \text{pu power.}\end{aligned}$$

Base Impedance: $Z_0 = 257.4\ \Omega = 1$ pu Ω.

Base Voltage: $V = 525$ kV $= 1$ pu V.

Base Current: $I = 1178$ A $= 1$ pu A.

Line Impedance and Load in Per Unit

$$\begin{aligned}X_L &= (D)(X_{L1})(0.94)\ \text{equivalent } \pi \text{ element}\\ &= (300)(0.53)(0.94) = 149.5\ \Omega\ \text{line inductive reactance.}\end{aligned}$$

$$\begin{aligned}X_L\,\text{pu} &= (149.5)/\text{base impedance}\\ &= (149.5)/(257.4) = 0.58\ \Omega/1\ \text{line inductive pu reactance.}\end{aligned}$$

$$\begin{aligned}X_C &= (X_{C1}/D)(0.97)\ \text{equivalent } \pi \text{ element}\\ &= (125{,}000/300)(0.97) = 404.2\ \Omega\ \text{line capacitive reactance.}\end{aligned}$$

$$X_C\,\text{pu} = (404.2)/(257.4) = 1.57\ \Omega/1\ \text{line capacitive pu reactance.}$$

$$\begin{aligned}R\ \text{pu} &= (R)(D)/257.4\\ &= (0.02)(300)/257.4 = 0.0233\ \Omega/1\ \text{line pu resistance.}\end{aligned}$$

$$P_n\,\text{pu} = 2\ \text{pu} = (2)(525)^2/(257.4) = 2142\ \text{MW design loading.}$$

$$I_p\,\text{pu} = (2142)(1000)/(525)\sqrt{3} = 2355\ \text{A} = 2\ \text{pu A.}$$

Series Capacitive Compensation in Percent

From Eq. 5.8 (per-unit quantities except where noted),

$$X_{se}\,\% = 100\left[1 - \frac{n(E_R\,\text{pu})\sin 35°}{(I_p\,\text{pu})(X_L\,\text{pu})}\right]\% \tag{5.8}$$

$$= 100\left[1 - \frac{(1.03)(1)(0.574)}{(2)(0.58)}\right]$$

$$= 49\%\ \text{series capacitive compensation}\ .$$

Shunt Reactive Power Compenation

From Eq. 5.12, receiving-end shunt capacitive compensation (per-unit quantities except where noted),

$$\Delta X_C = 100\left\{\frac{X_C\,\text{pu}}{X_{LC}\,\text{pu}}\left[1 - n\cos 35° + (I_p\,\text{pu})(R\,\text{pu})\right] - 0.5\right\}\% \tag{5.12}$$

$$X_{LC}\,\text{pu} = (0.58)(1 - 0.49) = 0.296\,\Omega\,\text{pu}$$

$$\Delta X_C = 100\left\{\frac{1.57}{0.296}\left[1 - (1.03)(0.819) + (2)(0.0233)\right] - 0.5\right\}\%$$

$$= 58\%\ \text{receiving-end shunt capacitive compensation}\ .$$

Line-Charging MVA $= E^2/X_C$

$= (525)^2/(404.2)$

$=$ 682 MVA.

Reveiving-End Shunt Capacitive Compensation = (682)(0.58) = 395 MVA.

Total Shunt Capacitive Compensation = (2)(395) = 790 MVA.

Series Capacitor Rating—MVA

The series capacitors must be rated to carry the current, I_L, flowing in the shunt-compensated line under maximum load conditions. This current is the phasor sum of the load current component, I_p, and half of the total compensated circuit shunt capacitive current, I_{CC}; that is,

$$I_L = I_p + j(I_{CC}/2)$$

$$= 2355 + j1809 = 2490\,\text{A}/19°\ \text{(in polar coordinates).}$$

The series compensation, then, is

$$X_{se} = (0.49)(149.5\ \Omega) = 73.2\ \Omega\ \text{capacitive reactance at 2490 A.}$$

Total series capacitors = 1360 MVA for the three-phase bank.

EXAMPLE B.2—CALCULATION OF LOAD-REJECTION COMPENSATION

Load rejection on long lines may lead to high receiving-end voltages from the Ferranti Effect. This example illustrates the calculation of the reactive power compensation needed when the receiving-end voltage may reach unacceptably high levels. The transmission line assumed for this is the same one used for examination of series and shunt capacitive compensation for loads up to twice the uncompensated SIL, a 300-mile, 525-kV, triple Chukar circuit.

Assumed voltages are

$$\begin{aligned} E_S &= (1.03)(E_{R0}) \text{ prior to load rejection} \\ &= 541 \text{ kV}. \end{aligned}$$

The rise of the receiving (open-end) voltage, E_R, is to be limited to 5% over its nominal 525-kV value.

$$\begin{aligned} E_R &= (1.05)(E_{R0}) \\ &= 551 \text{ kV}. \end{aligned}$$

See Example B.1 for the line impedance constants and for percent series compensation.

From Eq. 5.17, percent shunt inductive compensation for load rejection,

$$\Delta X_L\% = \left[0.5 - \frac{(E_R - E_S)}{E_R D^2\left(1 - \dfrac{X_{se}\%}{100}\right)} \cdot \left(\frac{X_{C1}}{X_{L1}}\right)\right]100 \tag{5.17}$$

$$= \left[0.5 - \frac{(551 - 541)}{(1.05)(525)(300)^2(1 - 0.49)} \cdot \frac{125{,}000}{0.53}\right]100$$

$$= 40.7\% \text{ inductive compensation to limit } E_R \text{ to } 551 \text{ kV}.$$

$$100\%\,\Delta MVA_{sh} = \frac{V^2 D}{X_{C1}} = \frac{(525)^2(300)}{125{,}000}$$

$$= 662 \text{ MVA}.$$

$$\Delta MVA_{sh} = 269 \text{ MVA at } 525 \text{ kV (nominal voltage)}.$$

High-Value Series Reactance Compensation of AC Power Transmission Circuits

Alternating-current transmission circuits can be represented for performance analysis as equivalent series impedances terminated by equivalent shunt impedances that are practically purely capacitive (the "equivalent π" circuit). Active and reactive power flow over such a circuit is expessed as follows:

$$P_R + jQ_R = \frac{E_R}{Z}[E_S\cos(\delta - \theta) - E_R\cos\theta] + j\frac{E_R}{Z}[E_S\sin(\delta - \theta) + E_R\sin\theta]$$

where

$Z = (R_t^2 + X_L^2)^{0.5}$—line impedance,

$\theta = \tan^{-1}(X_L/R_t)$—line impedance angle,

$\delta = E_S^\circ - E_R^\circ$—voltage displacement angle.

The quadrature term in the above equation applies only to the transmitted reactive power and does not include any reactive power supplied by the terminal equivalent capacitors.

Normal high-capacity EHV ac transmission circuits have a relatively high X/R ratio, in the range of 20 to 30, giving an impedance angle, θ, approaching 90° and a value of line impedance, Z, approaching that of its series reactance, X_L. Consequently, for given values of E_S, E_R, and δ, the active and reactive power transmitted is approximately inversely proportional to the net line series reactance, X_{LC}. Series capacitor reactance compensation up to the order of 75% therefore increases power capacity by reducing the value of line impedance, Z, without reducing the net impedance angle, θ, below about 80°.

However, for extremely high values of series compensation (95 to 100%), the net line impedance angle, θ, approaches zero, thereby significantly altering the values of bracketed terms of the above power equation. This also reduces the line impedance, Z, as well to a value approaching the line resistance, R_t, usually a low value.

For an uncompensated line X/R ratio of about 25, 99% series compensation would reduce the impedance angle, θ, to about 14° and the net impedance to about 4.1% of the line's uncompensated value. For equal values of E_S and E_R at this degree of series compensation, a terminal voltage displacement, δ, of about 5° would produce the same power flow as 30° for the uncompensated case, but negative power flow for a 5° negative displacement would be about 50% greater in magnitude than positive flow for an equal positive angle.

For 100% series capacitive compensation and equal values of E_S and E_R, either positive or negative voltage displacement results in negative power flow proportional to $(\cos \delta - 1.0)$. That is, the synchronizing torque between the two voltages is negative. The resulting negative power flow can be compensated or reversed by increasing the ratio of E_S to E_R.

Increasing negative displacement of the sending system at 100% series compensation of the interconnecting ac circuit increases negative power flow, thus exerting a stabilizing influence at negative displacement angles when E_S is equal to or less than E_R. However, for increasing positive displacement angles, negative power flow would again increase, thus retarding the receiving system and promoting instability, unless the ratio of E_S/E_R were maintained equal to or greater than $1.0/[\cos(-\delta)]$. At any fixed value of δ, positive or negative power flow could be controlled by adjusting the values of the terminal voltages E_S and E_R. In this respect, control of ac power flow over a 100% series capacitive compensated line is similar to control of power flow over a dc line, that is, by adjusting the difference in voltages between the line terminals.

A passive load that is inductive, resistive, or capacitive would determine the value and displacement angle of E_R with respect to E_S. However, an active load, one containing generation which produces a countervoltage, would require interconnected system voltage control to maintain stability.

The following phasor diagrams and curves illustrate power system performance when applying high degrees of series compensation. Figure B.2 illustrates the effects on line current, losses, and reactive power flow of changes in load, voltages, and displacement angle for 100% series capacitor compensation. Figure B.3 shows how power flow changes with changes in series compensation at fixed positive and negative displacement angles for a typical HV (X/R = 10) and an EHV (X/R = 25) line. Figure B.4 is a plot of the family of real and reactive power flow curves for series compensation from 0.0 to 100% as functions of the displacement angle δ from 0° to 10°. Figure B.5 expands the plot of certain of the foregoing curves to the displacement angle range 0° to 20°. Note

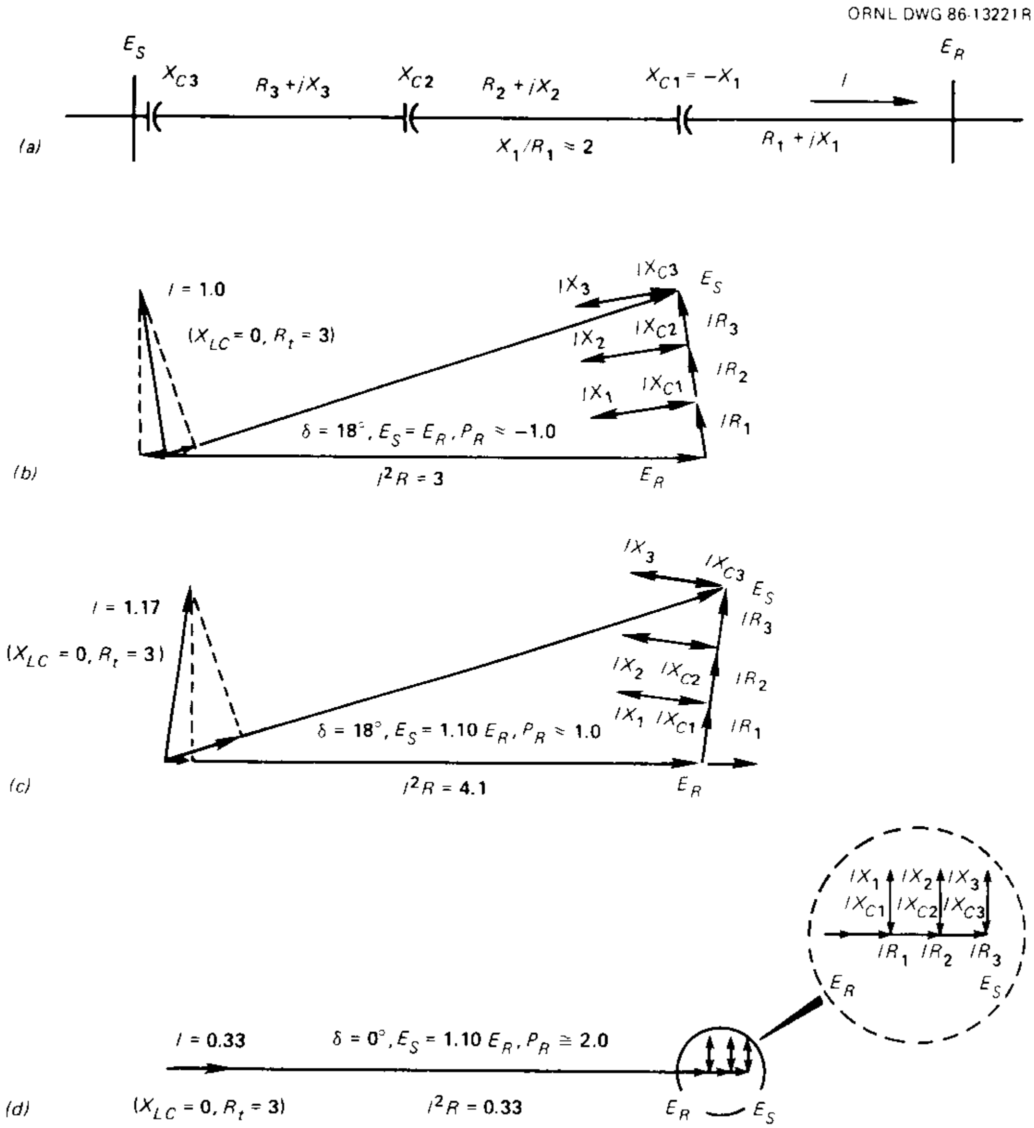


Fig. B.2. Phasor diagrams, approximate example of 100% series compensation.

$$P_R = f(E_S \cos\delta - E_R)E_R/R_t \qquad (X_L = X_{se}) \ .$$

That is, increasing δ decreases P_R for constant E_s, E_R; it also increases line current, losses, and reactive power. (Scales relative only.) (*a*), One-line diagram; (*b*), (*c*), and (*d*), phasor diagrams.

that at a displacement angle of ~13.5° the real power flow reverses for the 100% series compensation case.

Whereas a dc intertie between power systems prevents appreciable contribution of one system to fault duty in the other, an ac intertie provides fault contributions in inverse proportion to the fault impedance from the unfaulted system. Since series capacitive compensation effectively reduces the line impendance to the flow of fault current through the line, series compensation of an ac intertie increases the fault contribution from the sound system.

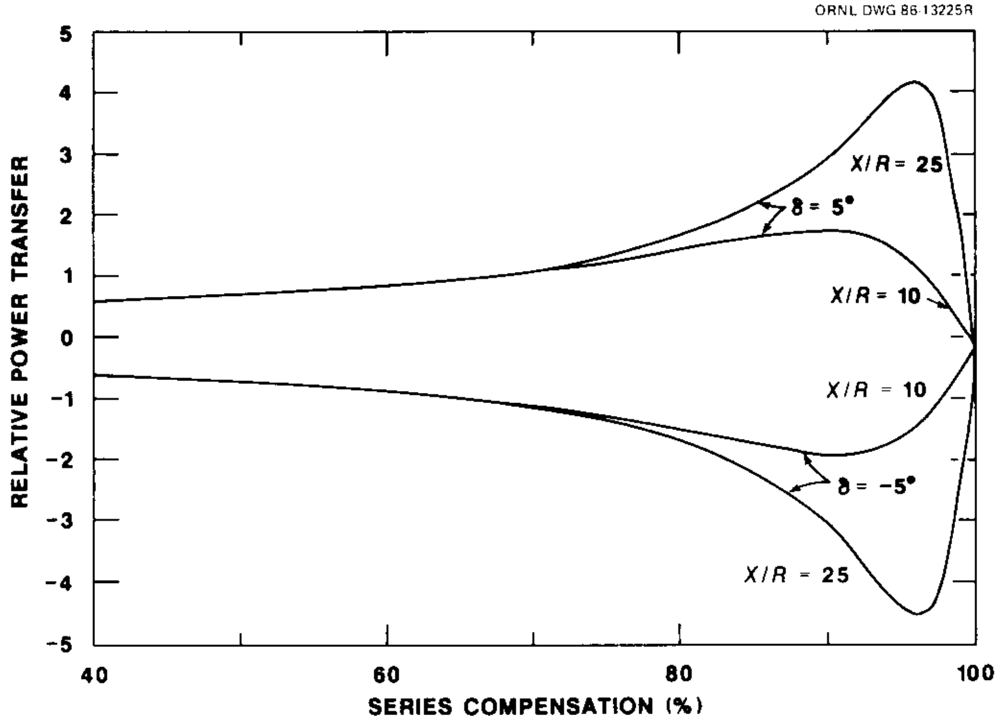


Fig. B.3. Power transfer as a function of the degree of series capacitive compensation at fixed displacement angle, $\delta = 5°$, terminal voltages, $E_S = E_R$, and uncompensated circuits $X/R = 25$ and 10.

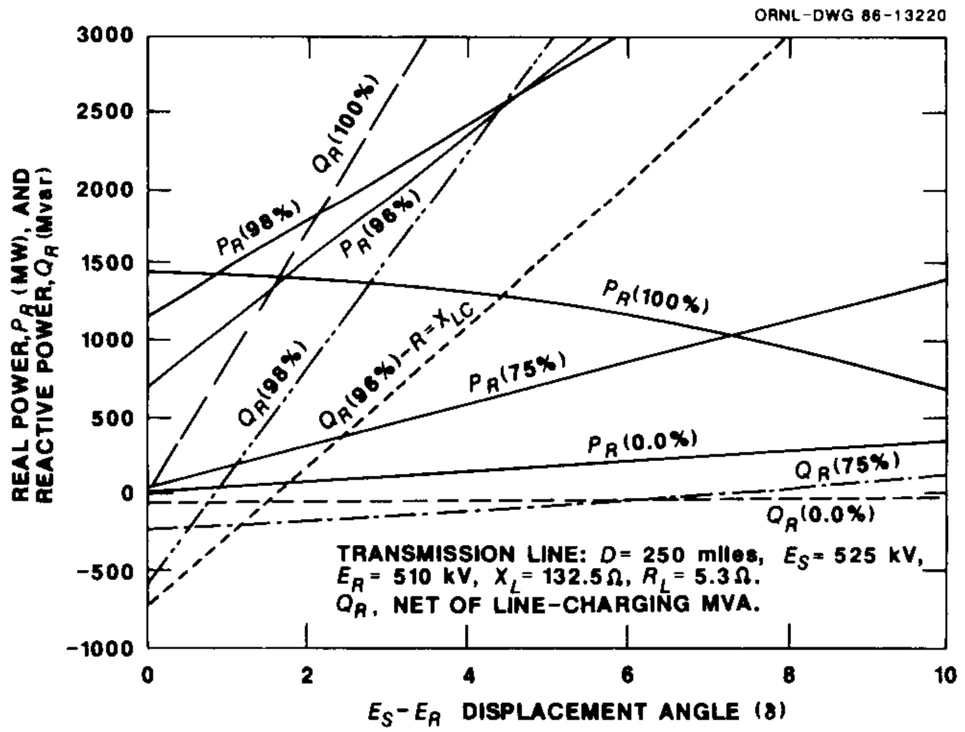


Fig. B.4. Example of real and reactive power flow over a given transmission as functions of displacement angle and degree of series compensation.

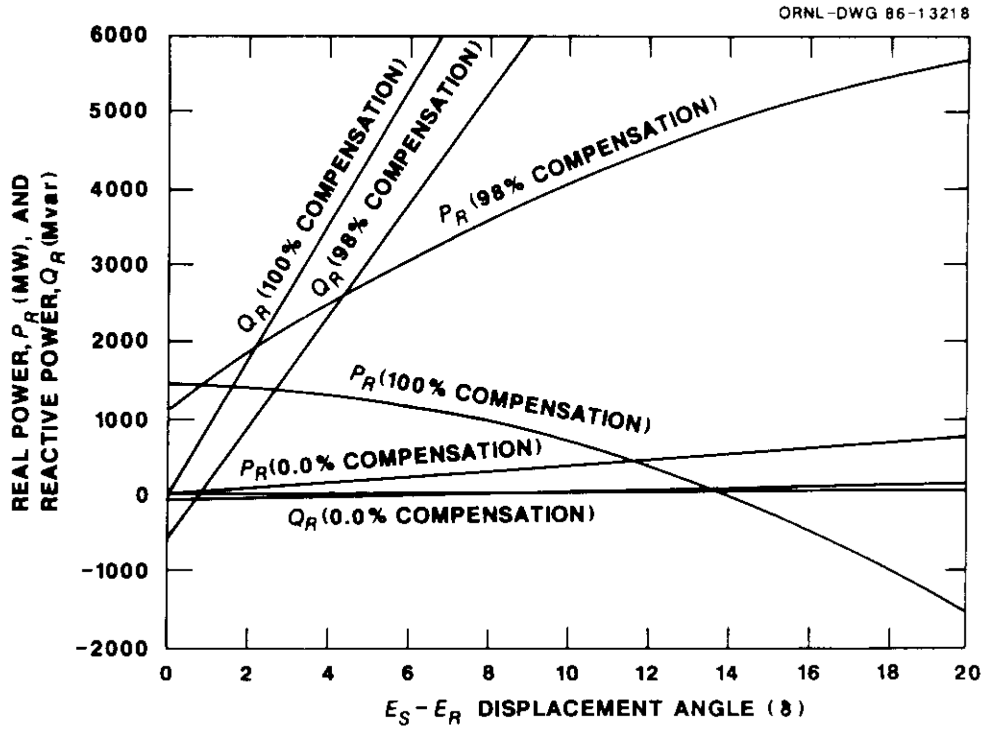


Fig. B.5. Expanded plot of real and reactive power flow for dispacement angles up to 20°.

For 100% compensation, the fault contribution may be excessive in terms of the series capacitor capability before the fault is removed from the circuit or substantially bypassed. Nonlinear metal oxide series capacitor shunting resistors may be adequate in some situations, while in others high-speed switching, capacitor shunting, or momentary intertie separation may be required to protect the capacitors or to reduce the fault current contribution.

A further consideration is that a 100% series capacitive reactance compensated ac transmission line has a primary series resonant frequency equal to the system frequency (e.g., 60 Hz). Lesser degrees of compensation result in subsynchronous primary resonant frequencies and may give rise to amplified torsional oscillations in certain connected synchronous or induction machinery. Large turbine generators radially connected with series-compensated circuits may experience this problem if not sufficiently damped by other loads or otherwise protected.

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