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HVDC Power Transmission Technology Assessment

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HVDC POWER TRANSMISSION TECHNOLOGY ASSESSMENT

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LIST OF ACRONYMS

ac	alternating current, also AC used
ACSR	aluminum conductor, steel reinforced
BTBDC	back-to-back dc converter station
CC	combined cycle (gas and steam) power plant
CCC	Capacitor Commutated Converter [Asplund, 1995]
CO	Colorado
CO_2	carbon dioxide
CT	current transformer
dc	direct current, also DC used
DSM	demand-side (load) management
ECAR	East Central Area Reliability Council
EHS	extra high strength steel (conductor)
EMF	electromagnetic fields
EPA	Electric Power Alert (periodical)
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESDD	equivalent salt deposit density - mm/cm^2
EUW	Electric Utility Weekly (periodical)
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
Genco	Generating Company
HPFF	high pressure fluid filled (cable)
HPO	high phase order (six or 12 phase)
HVDC	high voltage direct current
IPP	independent power producer
IS0	independent system operator
KCMIL	thousands of circular mils
KS	Kansas
kV	kilovolts
KW	kilowatts
LCC	line commutated converter
LTC	load tap changer
MAAC	Mid Atlantic Area (Reliability) Council
MAIN	Mid-America Interpool Network
MAPP	Mid-Continent Area Power Pool
MI	mass impregnated (cable)
mm	milimeters
MM	millions (such as dollars)
MUSD	million United States dollars
MVA	mega-volt-amperes
MVAR	mega-volt-amperes-reactive
MW	mega-watt(s)
MWHR	mega-watt-hour(s)
NERC	North American Electric Reliability Council
NESC	National Electric Safety Code
NOPR	notice of proposed rulemaking

LIST OF ACRONYMS - Continued

NPCC	Northeast Power Coordinating Council
O&M	operation and maintenance
PAR	power angle regulator
PIGF	paper insulated gas filled (cable)
PSC	Public Service Co. of Colorado
PTI	Power Technologies, Inc.
PV	photovoltaic (power source)
RDI	Resources Data International
ROW	right-of-way
RTA	Regional Transmission & Exchange Area
SCFF	self contained fluid filled (cable)
SCGP	self contained gas pressurised paper type (cable)
SCR	short circuit ratio = dc converter MW divided by ac system short circuit MVA
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SSSC	Static Synchronous Series Controller (a FACTS controller)
STATCOM	Static Compensator (a FACTS controller)
SUNC	Sunflower Electric Co.
SVC	Static Var Compensator
TCPAR	Thyristor Controlled Power Angle Regulator
TCSC	Thyristor Controlled Series Capacitor
Transco	Transmission Company
UG	underground
UPFC	Unified Power Flow Contoller (a FACTS controller)
US	United States
VSC	Voltage source commutated (converter)
WSCC	Western States Coordinating Council
XLPE	extruded cross-link polyethylne (cable)

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ORNL/Sub/95-SR893/1 "HVDC Power Transmission -Technology Assessment"
ORNL/Sub/95-SR893/2 "HVDC Power Transmission - Environmental Issues Review"
ORNL/Sub/95-SR893/3 "HVDC Power Transmission - Eletrode Siting and Design"

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ABSTRACT

The purpose of this study was to develop an assessment of the national utility system's needs for electric transmission during the period 19952020 that could be met by future reduced-cost HVDC systems. The assessment was to include an economic evaluation of HVDC as a means for meeting those needs as well as a comparison with competing technologies such as ac transmission with and without Flexible AC Transmission System (FACTS) controllers. The role of force commutated dc converters was to be assumed where appropriate.

The assessment begins by identifying the general needs for transmission in the U.S. in the context of a future deregulated power industry. The possible roles for direct current transmission are then postulated in terms of representative scenarios. A few of the scenarios are illustrated with the help of actual U.S. system examples. Non-traditional applications as well as traditional applications such as long lines and asynchronous interconnections are discussed. The classical "break-even distance" concept for comparing HVDC and ac lines is used to assess the selected scenarios. The impact of reduced-cost converters is reflected in terms of the break-even distance.

This report presents a comprehensive review of the functional benefits of HVDC transmission and updated cost data for both ac and dc system components. It also provides some provocative thoughts on how direct current transmission might be applied to better utilize and expand our nation's increasingly stressed transmission assets.

EXECUTIVE SUMMARY & CONCLUSIONS

Introduction

This project continues an effort that was started in 1992 wherein industry experts, including HVDC system suppliers, explored the concept of reducing converter station costs by about 50 % [Clark 1993; ORNL,1993]. The statement of work requested an assessment of the nation's transmission needs for the period 1995-2020 and how cost-reduced HVDC might help in fulfilling those needs. The goal of this Task was to assess whether HVDC could be cost-effective compared with ac transmission if the targeted 50 % reduction in converter costs was achieved in the future. The determination of how the cost reduction can be accomplished is not covered herein- That question is the subject of parallel investigations project 2000] that includes the development of advanced converters exploiting the benefits of forced commutation.

Project Methodology

The project began with a critical review of the functional needs for transmission in the United States for the subject period. To the extent possible, the anticipated changes in the industry leading to open access and competition were considered as the functional needs were identified. Recent reports by the North American Reliability Council (NERC) and specific utilities were reviewed to recognize their current plans for transmission upgrades between now and the year 2004. While there are 10,000 miles of new transmission scheduled for that time period, most of the individual projects are short lines (200 miles or less) and all of them, including the longer lines, are planned as ac transmission.

Initially, this task was to include a detailed analyses of several planned projects to evaluate the prospects for cost-reduced HVDC. However, those analyses were scaled back due to a lack of detailed planning data for those few projects that appeared promising and the general uncertainty of the relevant economic parameters that will prevail in the future competitive industry. Instead, comparison of HVDC and ac transmission is made for several representative scenarios where ac and dc would likely compete. These comparisons were made in qualitative and quantitative terms, the latter using the traditional "break-even distance" (illustrated in Figure 3.2) calculation for representative examples. Both overhead lines and cable systems are discussed.

Summary of Key Findings

Near-term plans for new transmission in the U.S. and Canada - as reported in NERC's Reliability Assessment report of 1995 - show little interest in HVDC at this time. Most reported transmission plans are for short lines and those few long line cases (mostly in western U.S.) probably will go forward as ac unless compelling techno-economic reasons are revealed. Additional transmission opportunities - beyond those reported to NERC for reliability assessment - may arise depending upon the evolving "new economics" of the competitive transmission business. For the foreseeable future, it is speculated that new generating capacity needs are most likely to be met by modest-sized gas-fired combined cycle plants. Those plants probably will be located as close to the major load centers as practical, thus pre-empting the need for long distance transmission lines for which HVDC have been preferred in the past. Converter station cost reductions will be vital if dc is to compete with ac for those short-haul, high power density applications. Section 2 of this report discusses the published plans and speculates further regarding the future of our nation's transmission needs.

Section 3 provides a thorough discussion of where dc is likely to compete with other technologies in satisfying the needs for transmission in the future. Direct current links will continue to be the only practical way to interchange power between the four asynchronous networks in North America. There will be applications for additional back-to-back links between the fringe regions of these networks. Since they tend to be modestly rated (200 MW to 1000 MW so far), emerging voltage source converter (VSC) technology should prove to be highly suited for future links of this kind.

Back-to-back links may also prove competitive with Flexible AC Transmission Controllers (FACTS) such as the UPFC (Unified Power Flow Controller) for rapid power flow control on ac lines within the network where a high degree of flow control flexibility is required. As greater flexibility and efficiency is demanded of our transmission networks, loop flows may not be tolerated. Strategically-located back-to-back dc facilities can help minimize loop flow problems and generally improve the flexibility of scheduling flows. In some instances, power angle regulating transformers and the UPFC cannot match the range of power flow modulation possible with a dc interconnection (especially if power reversal is required), as demonstrated quantitatively in Section 3.4 of this report.

In a highly competitive generation market, generating plants may operate a few years and be decommissioned when they are no longer economic. This could cause the need to relocate the asynchronous links periodically as power flow patterns shift. Learning from the experiences in the United Kingdom, where moveable static var compensators are in demand, relocatable back-to-back converter stations may find application in our future networks.

Overbuilding ac with dc on existing towers and / or replacing ac lines with dc could provide a dramatic increase in the power density on some transmission corridors. Overhead direct current lines demand less tight-of-way width than a comparably rated ac line. This is achievable with today's dc technology and, at least for point to point transmission lines. While there are technical challenges relative to the field effects and the electrical and audible noise associated with them, these are understood and should prove solvable. As discussed in a companion report entitled "HVDC Transmission - Environmental Issues Review", the electric and magnetic field created by direct current overhead lines are potentially less objectionable than the controversial ac EMF, providing a small edge over ac lines in the siting and licensing process.

Today's converter station designs are becoming more compact but much more could be done to develop terminals for inner urban applications. Also, the need to tap a dc line for intermediate loads will require new converter control of reactive power as well as active power.

Improved reliability and power quality may demand enough premium in future instances whereby replacing single circuit ac lines providing radial feed to some load areas with bipolar direct current circuits might be desirable. Such an example is discussed in Section 5. The concept may also apply well for new installations, perhaps utilizing low voltage dc cables to route the new circuits underground and submarine to serve hard-to-reach urban (virtual islanded) loads. This kind of application, at distribution class voltages (23 kV and below for instance), may be a place for the VSC technology to find a "high volume" market. Another natural application of VSC technology would be to serve loads on the physical islands on both coasts of the U.S. and Alaska.

With many of the major load centers located in proximity to the sea, lake or a large river, the possibility of using submarine cables to reach the load should be considered. Cable technology continues to advance so both ac and dc submarine cables could see increased applications. For submarine distances exceeding about 50 km (30 miles), dc cables must be used. Section 7 reviews the well-known reasons for this and gives a numerical example comparing a 345 kV ac cable with a ±400 kV dc installation.

Representative cost data was assembled to support quantitative cost comparisons of ac and dc options. Estimated costs for ac and FACTS controllers were derived from published sources. For up-to-date HVDC costs, three HVDC suppliers were sent a survey requesting current converter station costs. Section 4 summarizes all the cost estimates, some of which were used in studies documented in Section 6. The vendor survey also asked what future cost reductions they believed were feasible. The system suppliers confirmed that only incremental cost reductions (less than 20%) could be achieved with current line-commutated converter technology. They were reluctant to provide detailed break-down of how the incremental reductions would be accomplished. Elimination of the converter transformer could result in up to 20% reduction in the station's cost. However, there are significant technical challenges relative to valve design and filtering [Vithayathil, 1995] that must be addressed.

In the authors' opinion, the dual challenge of achieving a major technology advancement - to forced commutated converter technology for instance - and making a 50 % reduction in price simultaneously will be insurmountable unless the volume of business is large enough for competitive forces can act effectively. Some of the potential applications for direct current transmission suggested by this investigation may increase volume to help in achieving the targeted cost reduction. However, the quantitative economic comparisons of HVDC and ac are reported in Section 6 with the amount of cost savings varied between zero and 50 %. The results reported therein show that for certain applications, the cost-reduction need not be half for dc to gain an advantage.

Section 6 of the report analyzes several representative "scenarios" where ac and dc are compared for long-haul power transmission of 500 - 1000 MW. These results should provide food for thought for future planners facing the challenges of a highly competitive, financial-performance-driven power delivery business. If the "new economics" of that competitive transmission business provide incentive to minimize the cost of transmission losses, direct current may be preferred in more cases. Results given in Section 6 indicate that HVDC could be more economical than ac even for lines shorter than 200 miles, provided losses are valued at about $2000/KW and the 50 % converter cost reductions can be achieved. However, at today's HVDC converter costs and typical line loading levels, the results confirm that lines shorter than 400 - 500 miles will be more economic as ac lines. Assuming that the new competition will cause ac lines to be loaded closer to their thermal limits, then the future cost of transmission losses can cause a decrease in the break-even distance, thus a shift in favor of HVDC.

With higher loading, reactive compensation of ac lines will be necessary in more instances than is common today. The analysis in Section 6 included the cost of conventional reactive compensation means for purposes of estimating ac line costs. Adding cost for FACTS controllers in an ac option might further reduce the break-even distance, but how much will be very project-specific. Estimating costs for FACTS controllers are given in Section 4, although that data was not used for the break-even-distance evaluations in Section 6. The only mature FACTS controller, the Static Var Compensator (SVC), typically costs two or three times the cost of switched shunt capacitors, so the latter lower cost approach was assumed in Section 6.

The capacity value of a transmission line can also have a bearing on it's long-term cost. If the evaluated cost of a transmission line bears the potential cost of make-up power (capacity) for extended circuit-outage conditions, a double-circuit line will enjoy some advantage over a single-circuit line. Section 6 explored the potential benefits of bipolar (double-circuit) dc lines versus single-circuit ac lines with capacity values from zero to $300/KW. For selected cases, the capacity value of the line added sufficient "cost" to the ac option that HVDC was more economical at any distance.

One quantitative assessment in Section 8 compared new generation near a load center versus installation of a 90 mile ac transmission line with a back-to-back dc station to serve the load from an adjacent but non-synchronous ac network. The most cost-effective approach in that case was a 345 kV ac line with a back-to-back dc interconnection. An HVDC line was too costly for such a short distance, and the generation was more expensive that both transmission options.

There is a possibility that further splits in our ac networks might be convenient or necessary. Such splits may be desired to prevent loop flows and other transmission constraints from frustrating open and efficient use of the transmission grid. A purely technical reason could also make further divisions desirable. That is, increased regional generating capacity without a corresponding increase in transmission capacity across key transmission 'interfaces between generation/load regions could lead to reduced synchronizing capability on those interfaces. Section 8 addresses two examples where future synchronizing capability between regions interior to the eastern U.S. network might diminish to levels low enough to warrant some action. In such cases, it may prove more economical to split the ac network and reconnect at selected buses with back-to-back dc links than it would be to add new ac lines or reinforce the existing ac lines.

Conclusions

Except for the interconnection of asynchronous networks, where HVDC will continue to enjoy virtually no competition from ac transmission options, the choice between ac and dc will require a case-by-case detailed economic comparison. This investigation has confirmed our previous knowledge in that regard and revisited the traditional 'break-even distance" in light of the planned increase in ac line loadings. If losses are heavily penalized in our future power delivery business, HVDC should realize increased consideration. If the cost of losses is somehow rendered unimportant in the future, then prospects for expanded HVDC application in the United States will diminish also.

To achieve the targeted reduction in prices (50 %) and benefit from advanced technology, a large market must evolve to allow competition between suppliers. This investigation has explored non-traditional applications, some of which are at voltage levels previously not considered HVDC or even transmission. The use of VSC-based back-to-back dc instead of FACTS controllers for power flow control is one of them. It may be just such unusual applications that create a sufficient volume of business to stimulate the necessary development and the targeted cost reductions. Those reductions may then impact HVDC across the board.

The future of power transmission as a business is uncertain, but it is sure to offer challenges and opportunities for breaking the old paradigms relative to applying direct current technologies.

1. INTRODUCTION

1.1 BACKGROUND

The United States Department of Energy (DOE) initiated a dialog with the utility industry in 1989 to identify transmission and distribution research needed to prepare for the year 2020. Leaders of utilities, equipment suppliers, engineering consultants and universities conferred at length and participated in workshops to discuss the future needs of the US transmission systems. Part of those discussions were devoted to the potential future role of high voltage direct current (HVDC) systems. The participants concluded that future HVDC systems must incorporate the functional performance advantages afforded by forced-commutated converters to enable them to meet the need for higher system load densities, more controllability, and reduced short circuit capacities in the served load areas. Also, a dramatic reduction in HVDC converter station costs must be realized to keep pace with parallel developments and growing capabilities of ac systems employing flexible ac system transmission (FACTS) controllers.

In mid 1994 the DOE issued a request-for-proposals covering a broad range of issues associated with the development of advanced technology HVDC systems with a goal of reducing the cots of a HVDC converter terminal by 40-50%. Advancements sought included new converter configurations, advanced and cost-reduced valves and controls, schemes including advanced transformer designs, or no transformer at all. Parallel research also requested was to identify the potential applicability of such "advanced capability, cost-reduced" HVDC considering technical, economic and environmental issues. One of the possible means for reducing HVDC system costs, namely the notion of operating full time in monopolar-earth-return mode was to be explored in the asked-for research.

i.2 SCOPE OF RESEARCH

The scope of Project IIA - Technology Assessment includes two areas of concentration. The first is the subject of Task 1 entitled "'Benefits and Alternatives Assessment. This task focuses on the nation's future needs for transmission with an emphasis on those needs that can be best served by forced-commutated direct current systems. To the extent possible, an economic comparison is made between advanced-but-cost-reduced HVDC (the new HVDC) and competing ac approaches. Task 1 results are covered in this Part 1.

The second area of focus in this project is that of Task 2 - Environmental Issues Review. That task researched and documented the current state of our knowledge in environmental effects of dc fields and compares them with fields caused by ac lines. The effects of dc fields on other electrical equipment and on the health of humans, animals and plant life is covered. Results from Task 2 are reported in Part 2.

1.3 PROJECT APPROACH

Task 1 - Benefits and Alternatives Assessments, began with a summary review of published plans of the US utilities to determine where and how many transmission additions are anticipated. Publicly-available utility data covers commitments and speculations out through the year 2004. That work is reported in Section 2. A few of the "planned" transmission additions suggested scenarios that were then studied, at least from a technical viewpoint.

Speculations beyond the year 2004, and even before, are uncertain since the US utility industry, as a business, is undergoing a revolution. The approaches and parameters of economic comparison for deciding between new generation versus transmission reinforcement or between alternative transmission approaches are changing. Additionally, increased competition in the industry frustrates reasonable attempts at obtaining reliable cost data for economic comparisons. Lastly, good cost (price) estimates for the new HVDC technology and competing ac / FACTS technology assumed in this assessment are not available at this time. Consequently, the few economic comparisons offered in this report must be viewed with caution.

The technology assessment task followed a "likely scenario" approach to identifying possible transmission projects where the "new HVDC" is likely to compete with ac approaches, with or without FACTS enhancements. Some new (analysis) work is reported here, and relevant prior works are revisited.

2. U.S. TRANSMISSION NEEDS

This section attempts to identify the future needs for new electric transmission and improvements to the existing U.S. power delivery networks. The near-term plans of the nation's utilities, as published in current annual reports to the National Electric Reliability Council (NERC), are summarized first. Those plans cover the years 1995 to 2004. This report speculates on the needs for the years 2005 to 2020 based upon the investigators' vision of the future competitive power industry. That vision was shaped largely by the published positions of the Federal Energy Regulatory Commission (FERC) and some of the industry leaders that are helping shape our future business.

2.1 THE PAST PROVIDES LITTLE GUIDANCE FOR THE FUTURE

Today, more than ever in the past, predicting the future needs and development of the nation's transmission system is complicated. As in most other industries, the electric utility industry is unlikely to experience rapid growth similar to that during WWII and the 20 years thereafter. The extreme demand for electric power to fuel that era's industrial growth resulted in the large and relatively successful power industry that exists today. A challenge confronts the industry now with the restructuring of the business of producing and distributing electric energy. It may help to recap some of the defining events that shaped the present status of the industry and speculate on how those events might effect its future.

The northeast blackout of 1965 and others that followed a few years later galvanized the industry to focus on reliability, as well as economics, in designing and operating the power generation and transmission systems. The focus on reliability cannot be lost as the industry redefines itself; a very complex goal in an unbundled, open access, totally competitive environment. The energy crisis in the 70's put the brakes on double digit annual load growth so the next decade saw a period during which few new generating facilities were commissioned, especially large ones. The use of nuclear for new power sources in the US ceased due to a number of issues, not the least of which is concern for public safety following the incident at Three Mile Island. The greatly reduced load growth focused more attention on smaller, less-capital-intensive generating facilities; thus making the large nuclear plant uneconomical as well as unnecessary.

For the near term future, most new generating facilities probably will be small-to-medium gas turbines, gas-fired steam and combined cycle plants. The deregulation of the gas industry stimulated competition to discover new sources and reduce costs of production and delivery. Add to this the enormous technical advances in gas turbine designs that increased ratings and efficiency while reducing emissions, and the choice for gas-fired power plants is clear. Due to their compactness and low emissions, gas-fired plants, located near urban load centers, will proliferate to the extent that pipeline capacity can keep up with the demand. The need for electric power transmission lines may be dominated by reinforcement of local networks to accommodate the "near-town" generating plants.

Coal, a resource our nation appears to have in abundance, may see increased use in the short term, but perhaps not in the longer term. Some utilities voice great concerns that FERC's open access initiative will favor the use of "dirty" coal plants over more expensive "clean" energy sources, at least in the short term. For instance, mid-west US utilities that operate coal-fired plants with their relative excess capacity and low-marginal-fuel costs, might compete favorably with new gas-fired facilities located in the east coast urban load centers. However, the existing transmission facilities connecting the mid-west coal plants to the east coast are inadequate [NERC,1995] to handle significantly increased power transfers. That would present a short term deterrence to such a scenario.

In the longer term, the increased use of coal will face strict environmental requirements. Plans exist to cap the sulfur dioxide emissions in year 2000, and nitrous oxides will be limited via some sort of incentive system. The combined investments in "cleaner" coal plants and more transmission capacity could quickly negate the apparent cost advantage between the two alternatives. In other regions of the US, the expense of environmental controls on new or old coal plants may be justified, when compared to alternatives [EUW, 1995].

Nuclear plants constitute about 20% of the nation's capacity but some 3 7,000 MW of nuclear generators are likely to be off line by 2015 [EPA, 1996]. Some would like to believe that nuclear might become acceptable again provided the issues of public safety and spent fuel disposal can be solved. However, the enormous capital outlay and regulatory risks for such a plant, new or refurbished, could render them uneconomical in a fully competitive power supply business.

Hydro resources are cost-effective to operate, but the number of potential new sites in the US is very small. Even if the sites could be found, large hydro plants are expensive to build and may be avoided for the same reasons as stated for nuclear plants. Furthermore, existing hydro facilities are at risk of being abandoned due to the increasing cost of complying with environmental initiatives requiring reduced flows or installation of fish ladders.

A fully competitive generation sector probably will find it difficult to justify investing in other renewable resource plants such as wind, solar, etc. unless customers are willing to pay extra for "green power". Distributed generation employing fuel cells for individual residences, although some years away, may begin to see application near the year 2020. Superconducting transmission also may be technically and economically feasible by then, but will not be a significant factor before.

The uncertainty of the industry restructuring process driven by FERC, and the nation's utilities needs to prosper in a slow-growth industry, make it difficult to even speculate where the opportunities for new or reinforced transmission will arise. Fortunately, the first decade of the target period of 1995 - 2020 is partially defined by the utilities' annual reports to NERC. The most recent of those reports/plans are summarized next.

2.2 TRANSMISSION PLANS FOR 1995 - 2004

For the next decade, as the industry is in transition, the need for increased electric power transmission facilities in the US will be driven by two basic factions. First, traditional utilities will add or refurbish transmission lines to maintain or improve reliability of service to their "native load" customers. Open access of the transmission systems may complicate this objective but it will continue to be a driving force to transmission upgrades. Second, traditional utilities and new "Transcos" will need to upgrade their transmission facilities to accommodate spot market or contractual deliveries of electric energy by IPP's, "Gencos", and other utilities. Power marketers who initiate and implement energy sales contracts or arbitrage spot market deals on the grid will also campaign for new or enhanced transmission as they see transmission contraints frustrate their profit-making goals.

Despite the growing uncertainties surrounding the industry restructuring, the transmission of bulk (wholesale) power has increased about 40% over the 1989-1994 time period [RDI, 1995]. Annual wholesale power transactions exceeded $57 billion in 1994. Investments by US utilities in transmission plant during the 1989 - 1994 period increased by 25%. According to NERC's Reliability Assessment for 1995-2004 [NERC, 1995; T&D, 1996], utilities in the US and Canada report plans to add about 18,000 km of transmission lines; an increase of about 5% to their current systems. During that same period, generation capacity is expected to increase about IO% from a current level of 802,000 MW, to meet an average annual growth in peak load of about 1.7%.

NERC concludes that the projected generation and transmission capacity increases, coupled with DSM programs, are expected to meet the anticipated demands of consumers in the US and Canada over the next ten years.

A cursory review of the NERC Reliability Assessment report, a report by Resources Data International Inc. (RDI), and the regional OE-411 reports from which much of the NERC and RDI reports are derived, revealed insights into the general conclusions by NERC. Selected details from those reports are summarized later in Appendix A The RDI report also discusses the probable direction of the industry as FERC continues to enforce its open transmission access policy and develop the tariff structure that will support that policy. Some instances of wholesale power wheeling in practice today may be encouraged by locally low tariffs. The implementation of the precepts of FERCs "mega-NOPR", by leveling the playing field, may eliminate some of the existing incentives for,wheeling while providing other incentives for wheeling.

Eventually, when a workable competitive framework emerges, the current bottlenecks in our transmission systems that frustrate universal open access to power market players, will be examined from a rational business viewpoint. Those bottlenecks that can be eliminated through economically sound and environmentally responsible transmission enhancements will be mitigated. Those that cannot be so justified will be deferred or ruled out indefinitely. The environmental and societal factors that frustrate transmission additions today will probably become more complex rather than simpler in the decades to come. The "new players" in the electric power market will find very few quick-and-easy solutions.

There appears [RDI,1995] to be significant differences in generation costs between some regions of the US. These differences are reflected in base-load lambdas reported by pools and individual utilities. At first, some of these differences suggest opportunities for economy interchanges that might *justify* new or strengthened transmission connections. For those cases where the necessary transmission distances are large (e.g. - $10/MWhr in Kansas compared to $20/MWhr in New England), the wheeling charges required by all the intervening transmission providers quickly offsets the potential benefits. In such long line cases, HVDC might be a technically feasible approach if the only costs were for the physical equipment to build the intertie. However, the costs to obtain the necessary permits and ROWs along such a long multi state path could render such a project uneconomic.

In some cases, there are lambda differences in adjacent areas of the US that could be exploited without long transmission lines. Such is the case between western Kansas ($10/MWhr) and northwest Texas ($14/MWhr). In that case, the amount of excess capacity in the lower-cost area that could be made available to the higher-cost area is not enough to pay over a reasonable amortization period for building transmission to exploit a mere $4/MWhr differential. Both an attractive price spread and sufficient capacity over a predictable period must be present to cover the financing of the transmission required to exploit the cost differential- Most of these "obvious" potential opportunities rapidly become system specific, thereby requiring knowledge not available in the public domain. Added to this is the enormous uncertainties caused by industry restructuring which could cause the cost differentials to vanish or become irrelevant.

All these factors make it difficult to identify obvious and specific transmission opportunities from which an estimate of the future market for reduced-cost HVDC can be established. An earlier study [Clark,1992] predicted the upper bounds of the opportunity for HVDC in the WSCC-US region Many of the possible projects identified as "HVDC opportunities" are shown as planned ac lines in the OE-411 for WSCC. As planned, they would employ conventional series capacitor compensation and conventional PAR's, where needed.

While a defensible HVDC market prediction is not possible for the reasons cited, the tentative plans in those references provide "typical scenarios" for comparing reduced-cost HVDC and ac, with or without FACTS enhancements. The scenarios discussed in this report are patterned after potential true-life transmission needs cited in one or more of the references. Some of the ideas are derived from the near-term plans provided in Appendix A, but are couched in a speculative view of the path the industry may follow during the transition to competition.

2.3 TRANSMISSION NEEDS FOR 2005 - 2020

The future needs for US power delivery systems beyond 2004 are largely undefined. Some hints were given in the regional summaries Appendix A For example, the plans show new ac and HVDC lines in WSCC intent on serving continued load growth in southern California. One can postulate that metropolitan areas such as Los Angeles, San Francisco, Seattle/Portland areas, Chicago, and the east coast ranging from New York through Washington D.C. will continue to grow. A general growth of industry in the south-eastern US and continued growth of energy needs in Florida can be predicted. A shift to electric vehicles in the large urban areas especially will stimulate an increased need for electric energy, if not peak demand.

What forms of generation and where they are developed relative to the loads is central in predicting what, where and how much transmission capacity will be required. Since the restructuring of the industry makes the former uncertain, the latter is also unclear. The following predictions by Dr. Paul L. Jaskow (head of Economics Department at MIT) are cited as a rough guide. Jaskow's article [Jaskow,1996] in The Electricity Journal, entitled "How Will it All End? The Electric Utility in 2005", reflects his views on the probable outcome of the current restructuring activities and what generating options will be in play by then.

Jaskow suggests that the 140 plus dispatch control areas will be reduced to about 24 Regional Transmission and Power Exchange Areas (RTA's). Generation will be fully separated from delivery and will operate in a competitive environment. Stranded assets will have been paid off by then. The transmission RTA's will be operated by Independent System Operators (ISO's) that have absolutely no financial interests in generators, distributors, or retailers that use the grid. The RTA's will have responsibility for controlling and maintaining the grid and as well as expanding the network facilities when required. RTA's will strive for minimum losses (part of their obligation to earn performance based compensation for network services) and will provide non-discriminatory access to all users of the network. There will be no "contract path wheeling" as we know it today, but access charges will vary by time and location to reflect "congestion" costs associated with "firm access" for the generator. Non-firm contracts will no longer exist.

While coal will appear competitive during the transition period through 2005, the carbon dioxide emissions will have reached "global warming alert" proportions worldwide, so that an excise tax on CO, will make coal uneconomical. The demand for natural gas will climb drastically and renewable energy technologies, wind especially, will see a revival in development, even without government subsidies. DSM and environmentally friendly distributed generation such as PV and solar units, largely dormant during the transition years from 1995 - 2004, will see an upsurge in development.

Nuclear waste management and the dismantling of aging nuclear plants will have reached a critical phase so the US government will create regional nuclear power corporations who will operate, maintain and dismantle the plants, charging the regional distributors and their customers for the cost of operating these facilities on a take-or-pay basis. Meanwhile, government R&D

will focus on developing small, inherently safe reactors that can be financed in the competitive market.

These predictions lend little insight into specific regional needs for transmission, but suggest some constmints on what types (and where) generation will arise. That is, taken literally, no new generation will be coal-fired and most will be gas-fired. With large energy (gas) companies already investing in gas-fired power plants, today's trend toward locating clean small, cost-effective gas-fired plants near the load centers will continue beyond 2005, at least to the extent that gas pipeline capacity into urban areas exists or can be inexpensively extended. Some previous studies [Clerici,1996] show that building and operating new HVDC electric transmission can be less costly than building and operating new gas pipeline into a near-load power plant. Eventually, all the near-load sites suitable for a power plant of any size could be occupied. Locating the plants further away and transmitting the energy in electrical form to the load will become a necessity.

2.4 SUMMARY

The future needs for transmission in the U.S. will depend on how the power industry evolves into unregulated and re-regulated sectors. The plans published by NERC suggest nominal reinforcements, with few clear opportunities for HVDC. However, the NERC report is focused on reliability and might not include transmission plans that are not necessary to meet minimum reliability criteria. New transmission projects envisioned by entrepreneurs intent on exploiting economic opportunities could be opportunities for HVDC as well. Never-the-less, this section suggests plausible scenarios that are explored further in the study.

3. MEETING TRANSMISSION NEEDS WITH HVDC AND AC

This section begins with a review of familiar functional comparisons between dc and ac transmission in Section 3.1. Next, Section 3.2 defines six functional needs of the U.S. transmission system that characterize the requirements for transmission enhancements in the foreseeable future. Section 3.3 then discusses how dc and ac, with and without FACTS enhancements (FACTS = Flexible AC Transmission System) are likely to satisfy those requirements. The last section provides a summary and speculates on the future application of high voltage direct current systems utilizing existing and developing technologies.

3.1 GENERAL COMPARISONS OF HVDC AND AC TIUNSMISSION

Comparisons between ac and dc have been made since the days when Westinghouse and Edison argued over which technology was better. HVDC has proven cost-competitive for long distances, and is the only practical way of interconnecting systems that cannot be operated synchronously because of different frequencies (not a problem in the U.S. except for some railroad and industrial power systems) or their dynamic properties are such that they cannot remain synchronized after disturbances. This section attempts to review some of the measures of comparison frequently applied to HVDC and ac lines. Cost differences are, of course, an overriding comparison, but cannot be generalized. Some relevant examples of cost comparison are provided later in Section 6.

3.1.1 Power Density Capabilities

The amount of power that can be transported on a given transmission corridor or ROW is called the power density. For long lines where stability is limiting, it has long been recognized that a bipolar HVDC line can deliver at least 2 times the power of a three phase ac line with siiar operating. For instance, the Quebec-New England Phase II ±450 kV dc line carries 2000 MW some 1500 km from northern Quebec to New England whereas two circuits of 500 kV ac, even with 50 % series capacitor compensation and FACTS controller would have diiculty remaining stable for that distance.

A bipolar HVDC line can fit in the same horizontal space as a single or double circuit ac line of similar voltage rating. Figure 3.1 shows the ± 450 kV line mentioned above compared to a typical single circuit 500 kV line and a double circuit-single-tower 500 kV line. For lower voltage lines, 230 kV and less, compact line construction could bring the ROW requirements for the ac line down somewhat. However, similar steps could be used on the dc line so the dc could still enjoy an advantage. High phase order (six or twelve phase) ac lines might compete favorably with HVDC based on space requirements.

For very short distances, ac with a UPFC or some other form of FACTS control that permits the ac line to operate up to it's thermal capacity, would make the ac and dc have comparable power density. As always, a cost comparison would determine the outcome, probably in favor of ac for the short line. However, if the present worth of the cost of losses over the expected life of the line was considered, the comparison could be close. This type of comparison is made in Section 6 of this report.

3.1.2 Power Control Capability

The power transferred on a HVDC system (line or back-to-back) is precisely controlled instead of being dictated by the load angle across the line. Therefore the conductors' current-carrying capabilities can be fully utilized, up to the thermal limit if necessary, without concern for system stability. Furthermore, the power across the HVDC system can be "dialed in" at the converters rather than forcing a particular generation dispatch as is the case with ac systems. Recently, FACTS technologies have been developed that can provide a measure of power flow control similar to a dc line. Sections 3.3.6 and 3.4 discuss the comparison between a back-to-back dc link utilizing voltage source converter technology and several conventional and FACTS power flow controllers.

3.1.3 Stability Enhancement Capabilities

When a dc line connects two parts of the same ac network in an optimum manner, the possibility exists that modulating the power on the dc line can be a stabilizing influence to the synchronous machines in the regions tied by the line. The HVDC terminals must be located where the modulation of power can be effective in adding positive damping to ac power oscillations. If the converter terminals are not in the "right place", then no manner of controlled power modulation can help the ac system. DC lines that interconnect asynchronous networks can provide active power / frequency stabilization and in some cases, stability enhancement of one or both of the systems.

In the past, power modulation has been useful in adding damping to post disturbance (small magnitude) oscillations. Rapid power ramping is employed some times to improve or maintain transient stability. Large magnitude modulation or power ramping is not always effective, however. That is due largely to the fact that past dc converter technology was unable to provide ac voltage (reactive power) support independent from active power modulation. In fact large active power changes that should assist the ac system remain stable can instead reduce the ac system's stability by imposing a dynamic reactive power demand on the ac system and collapsing the voltage. Advanced forced commutated converters of the future will be capable of providing both functions, independently.

HVDC lines probably will not be added to an ac system simply for stability improvement; but can supply same if strategically positioned to do so as an ancillary function. Most FACTS controllers are expressly intended for ac system stability enhancement and will be strategically located for maximum stability benefit. Clearly, they will be more effective than dc in this function.

3.1.4 Reliability

A great deal of attention has been given to reliability of HVDC systems as they assume a larger role in transporting power in our systems. By any measure HVDC systems in the U.S. have been quite reliable. Barring natural disasters like the earthquake that destroyed the Sylmar terminal of the Pacific NW dc intertie, availability figures are respectable. For instance, except for scheduled outages, the 2000 MW Sandy Pond terminal has been available greater than 99 % of the time.

Reliability or availability numbers are frequently misunderstood and often misquoted so this section will avoid detailed comparisons. Suffice it to say that future dc converter systems should only get more reliable as the technology matures. The elements of a dc terminal that are most critical are the transformers, valves and the controls. The transformers are the most significant elements in outage statistics, since the replacement time is substantial. Due to the complexity of controls, they have been responsible for much of the unavailability in past systems. However, with digital controls maturing, they are becoming more reliable and it is less costly to build-in redundancy.

The valve sub systems are continually evolving - very few systems are duplicates - so they have been responsible for a share of the down-times reported. Since valve subsystems have become more modularized and incorporate redundant thyristors, the down-time attributable to valve failures generally is in retreat. Introducing a new technology with GTO's or some other turn-off devices, may of course bring a temporary increase in failures, but built-in redundancy can blunt the impact on overall converter availability. Since exploitation of turn-off devices in future HVDC systems should make them virtually universally applicable - weak systems as well as strong - standardization should be possible. With standardiition should come increased reliability.

Compared to a HVDC terminal station, an ac substation is less complicated and therefore potentially more reliable. This has been a major factor in the past acceptance of HVDC transmission. However, introducing FACTS technologies involving semiconductors similar to those in future HVDC systems will cause ac "terminals" to encounter similar availability problems. Eventually, the reliability of FACTS controllers, with their large number of subsystems like a HVDC station, will mature and the ac and dc "terminals" may have comparable reliability.

3.1.5 Losses

The valves, harmonic filters and other elements of an HVDC station that are absent in an ac substation make the HVDC terminal more lossy than an ac line "terminal". However, the ac line losses are typically more than in a dc line of comparable voltage rating and carrying the same power. At some length, called the "break-even" or "crossover" distance, the total system cost (including the cost of supplying the line plus terminals losses over the expected life of the line - in present worth terms) is less for the dc line. (See Figure 3.2). The break-even distance will vary depending on many system-specific factors, but is on the order of 800 km (500 mi) today [Hingorani,1996].

The losses for a typical static var compensator (a mature FACTS control device) is on the order of 1% of its MVAR rating and the estimated losses of a STACOM (with 1996 technology) is about double that value. Estimates of losses for UPFC and other inverter-based series FACTS controllers range are somewhat greater than about 2% of MW or MVAR rating as well. Liberal use of these ac system support devices will increase the cost of losses in our ac systems. Further, the increased transmission capability unleashed by these FACTS controllers will increase the line losses substantially. New low-loss line designs (using high temperature superconducting components for instance) may evolve in time, but for the foreseeable future, losses are going to rise.

Again, the cost comparison between ac, with or without FACTS, and dc is system-specific so a general treatment here is impossible. Section 6 revisits the "break-even-distance" concept in light of the probable increase in system losses as we increase the utilization of existing transmission lines in limited corridors.

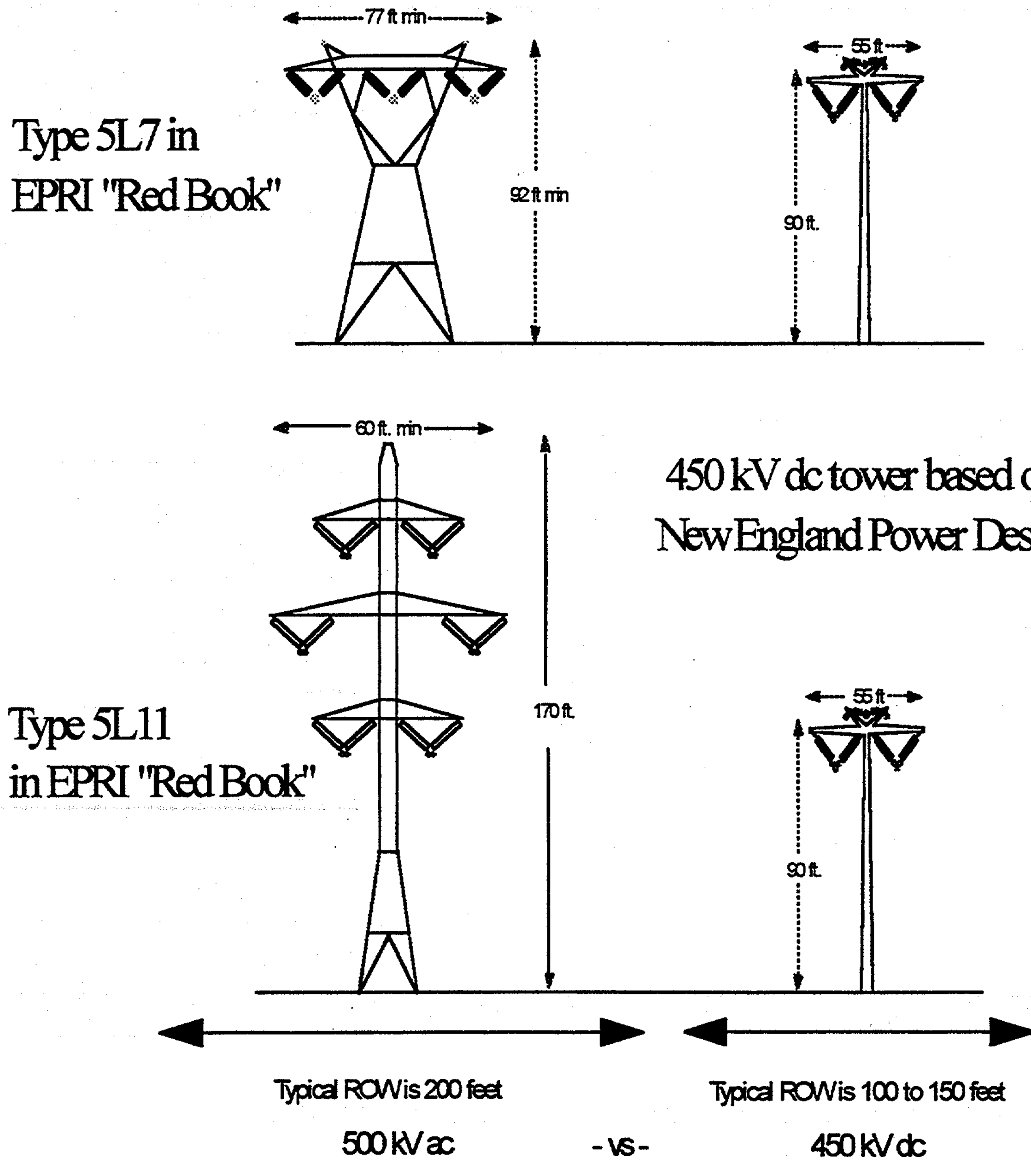


Figure 3.1 Comparison of Typical 500 kV ac and ±450 kV dc ROW Requirements
a) Single circuit 500 kV tower based on type 5L7 in EPRI "Red Book'
b) Double circuit 500 kV tower based on type 5L11 in EPRI "Red Book'
a) & b) A ±450 kV HVDC tower based on New England Power Design

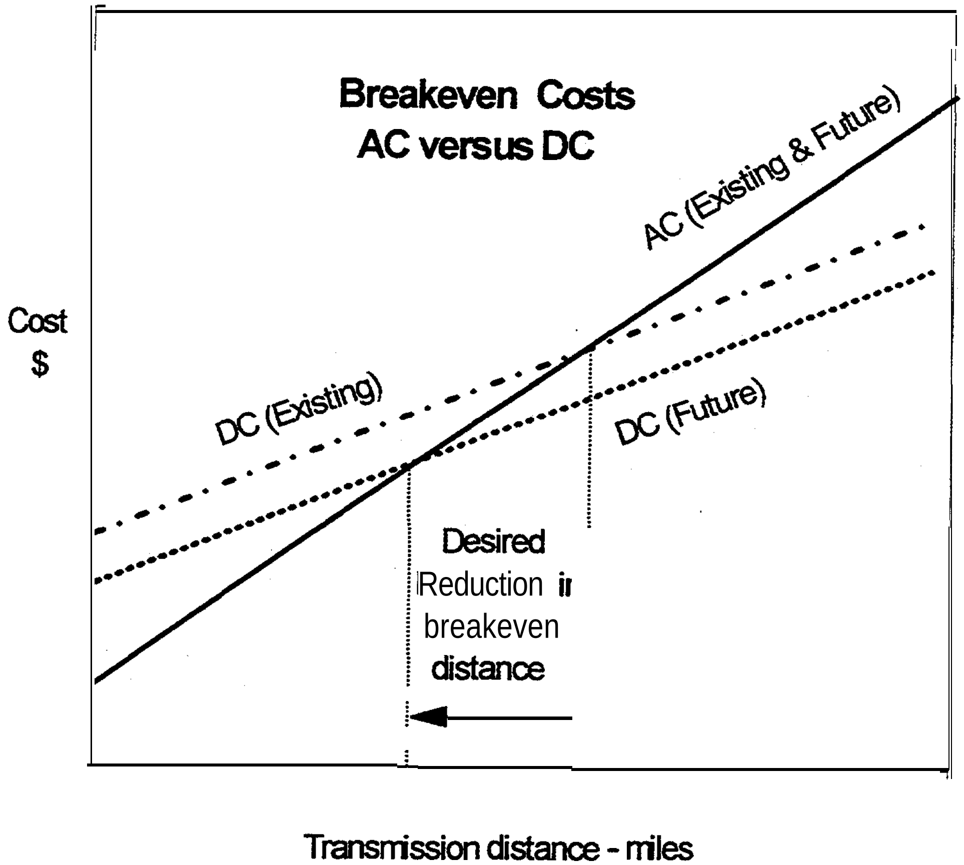


Figure 3.2 Illustration of Break Even Distance Concept

3.2 CHARACTERIZATION OF TRANSMISSION NEEDS

The functional needs of the future US power system are broadly defined and discussed in this section. Subsequent sections focus on how HVDC, conventional ac, FACTS-enhanced ac, and unconventional ac approaches might serve those functional needs.

Transmission needs that could be met with HVDC are characterized in the following six broad categories:

1. Integrate remote energy resources
2. Increase import capability into congested load areas
3. Enhance utilization of bulk power networks
4. Interchange energy between asynchronous networks
5. Serve isolated load areas
6. Power Flow Control

While there is some overlap between categories, they are discussed separately in the above sequence.

3.2.1 Integrate Remote Energy Resources

Remote energy sources may be divided into transportable and non-transportable resources. Coal, gas, and oil are the more common portable resources. They can be extracted and transported to a generating site as near as practical to the electrical load center. Alternatively, the resources can be burned at the point of extraction as in the case of mine-mouth (coal) plants. Natural gas can be utilized on site also, as there is little refining necessary. In the case of oil, it is more common to transport crude to refineries and the refined products are piped to the generating plant. Non-transportable resources include geothermal, wind energy and hydro resources which need to be converted to electrical energy by an on-site turbine generator.

The current trend is to add gas-fired thermal capacity as close to the load as practical or where gas is readily available and access to the transmission grid can be achieved with justifiable expense. This trend will continue into the next century as noted in Section 1. In large cities like New York, the future may even see small combustion turbines located atop buildings from which they will serve the surrounding neighborhood as well as the immediate building load. However, the need for long-haul electric power transmission will continue to arise in the future.

In-network Resources Remote From Load. Some new central-station power projects remote from load centers will be developed. Coal may become competitive with gas during the subject period but new hydro, nuclear and oil-fired plants are not likely to play a significant role in future generation expansion scenarios. Existing coal-fired plants in the mid-west, the western and southeastern regions may be expanded to serve future load growth.

For example, new and expanded mine-mouth coal-tired generation in Wyoming would be attractive because the coal is low sulphur content compared to Midwestern coal. Additional coal plants fired by high sulphur coal might be competitive if clean coal techniques are advanced. In all cases, the cost of transmission must be reasonable.

Remote Sources Out of Network or Isolated. Some of the new generation required before the year 2020 will be remote from the loads and, perhaps, remote from existing bulk power grid. Renewable resources such as hydro (small and large), wind energy, geothermal and solar power sources frequently fall in this category. Many of the smaller renewable resources will be exploited within the US but large hydro resources are available only in Canada. Perhaps resources in Mexico and other regions of Latin America will become attractive before the year 2020.

3.2.2 Increase Imports Into Congested Load Areas

The need for electricity in large metropolitan areas such as New York City, Los Angeles, Chicago, etc. will continue to grow even with continued use of demand side management. Many regions have substantial generation reserves now, however, continued load growth and unit retirements, will eventually require added generating and / or import capacity.

In some areas, new environmentally-acceptable generation will be commissioned, and some inefficient units will be repowered with gas. Distributed generation sources may proliferate in some areas, but probably not before 2020. The areas where new generation, large or small, is impossible to site, the growth in demand must be met with increased import (transmission) capacity.

Utilization of Existing Corridors. Since new transmission rights-of-way (ROW) will be extremely difficult to obtain the first choice will be to exploit existing corridors. This will involve squeezing new circuits on existing ROWs, overbuilding on existing towers, increasing operating voltages, employing series compensation and/or FACTS enhancements, or rebuilding with high phase order transmission or HVDC.

New Transmission Corridors. In some cases the existing corridors may just not suffice. Then new ROW's for overhead, underground and some submarine transmission will be required. Finding ROW's for new overhead lines will be difficult and costly, and success may require EMF reduction schemes and compact line construction. Underground and submarine circuits may be the only choice, in time, despite the extreme cost. This is already the case in The Netherlands and some Scandinavian countries

3.2.3 Enhance Utilization of the Bulk Power Networks

Some of the transmission lines in the bulk-power interconnected networks in the US (eastern western and Texas) are under-utilized relative to their thermal capacities, while others are heavily loaded at times. Reasons for this include stability constraints and parallel flow inequities (loop flow), both of which are frequently difficult or costly to mitigate. As electric consumption continues to increase, these problems and others must be solved.

Simultaneously, the industry trend toward competition will lead to "pay-for-performance" transmission facilities. This will doubtless require investment in the bulk power network facilities to increase capacity and maintain reliability. The functional needs of the bulk-power transportation business will be met with a combination of the following approaches.

Increased Stability of Bulk Power Network. *As* discussed in Section 3.2.2, the need to deliver increased power to load areas will require reinforcement of entry corridors. Likewise, existing transmission in the network feeding the entry corridors will require upgrading to eliminate bottlenecks. Many of the current bottlenecks in our networks are due to stability concerns. This is true in some eastern U.S. systems as well as in the "long-line world" of the western US.

Ofcourse, the first choice would be to add stability-enhancing equipments to the existing transmission lines and substations. A dramatic increase in the use of power electronics is anticipated in the future to help achieve the needed increased capacity, while maintaining stability, all without new transmission circuits.

However, new transmission circuits and even new ROWs will be needed to strengthen the three ac interconnected grids in the US. Employing power electronic enhancements in those new lines at the outset should help minimize the number of circuits that must be added.

Reduced System Losses. Increased utilization of existing transmission facilities, without reconductoring, will result in increased losses. To remain competitive, transmission providers (or their generating and distributing clients) may want to reduce losses. In the past, some utilities have had little incentive to make investments to reduce power system losses because the costs of these losses were simply passed on to the customers. In the new competitive climate with some companies specializing only in transmission, the cost of losses can affect the bottom line more directly. Transmission loss reduction also might be part of a demand side management program. For all these reasons transmission loss reduction is likely to be more important in the coming years.

Superconducting transmission is unlikely to be commercialized before 2020, so conventional solutions will be employed. This will lead to reconductoring, retensioning of conductors, addition of reactive compensation and, in some cases, increased operating voltage. Now, and for some time to come, the low cost of gas for fuel will make the cost of losses low. Even if the transmission owner / operators' clients choose to simply pay for the losses, our need to safeguard the environment will provide motivation to keep losses in check.

3.2.4 Interchange Energy Between Asynchronous Networks

The four power networks serving eastern US/Canada, western US/Canada, ERCOT (Texas), and Quebec are asynchronous at this time. They are interconnected only by HVDC ties. While ac interconnections are not impossible, they could be very costly. A commonly-used "rule of thumb" holds that the ac ties between adjacent networks must be rated for greater than 10% of the total generating capacity of the smaller system. Anything less could risk loss of synchronism following any disturbance.

Today, utilities with customers on both sides of the east/west interface can justify a modest sized interconnection across the interface so they can better serve all of their customers. However, they probably could not justify a 10,000 MVA ac tie simply to serve a 100 MW wholesale power customer on the other network. In the future, regional transmission groups entrusted with providing maximum access to the competitive power generators probably will demand the flexibility of exchanging additional energy across the asynchronous interfaces.

In time, some transmission "interfaces" internal to the four networks may become too weak relative to network sizes to maintain synchronism, thereby begging substantial reinforcements. Instead, the weak ac lines might be severed, thereby creating additional asynchronous subnetworks. Such an example is studied in Section 8.

3.2.5 Serve Isolated Load Areas.

Loads on physical islands located some distance from the mainland grid are frequently operated isolated relying entirely upon on-island generation. Some mainland load areas are also isolated or virtually isolated by distance from the main grid.

Island Loads and Systems. Isolated load areas that depend entirely on local generation are uncommon in the continental US. Some islands off the coast of the US are served exclusively by oil-fired generation or have minimal cable capacity to the mainland for supplementing their on-island generators. In time, even small, well-developed islands could need increased supply. Where on-island resources are limited or too costly to operate, existing cable connections may need to be upgraded or new ones, installed.

The string of islands that form Southeastern Alaska are largely asynchronous and probably will remain so through 2020 since the loads are not expected to grow dramatically. Long range plans show interconnections between the islands as well as new generation.

Radially Fed Loads. Some load areas within the mainland US are virtually isolated in that they are connected to the bulk power grid by a single circuit, low voltage transmission line. Some rely on local generation for primary supply but others have no local supply. As load grows in such areas, the choice between installing local generation or additional transmission capacity must be made. If there is no local generation to begin with, the reliability issue may become acute. As more consumers adopt electronic loads, they will demand high quality power as well as reliable service.

Such circumstances are more likely to exist in the mid section of the US where there may be as few as one customer per square mile compared to 1000 and more per square mile in coastal urban areas. Only very cost-effective means can be justified to provide adequate reliabii and quality simultaneously to those "isolated" loads. The solution in such areas may need to be implemented in the "sub-transmission" or distribution systems.

3.2.6 Power Flow Routing and Control.

Power marketers and system operators will desire more power flow directional control than is afforded in our networks today. To be profitable, a "pay-for-performance transmission company' will be compelled to avoid bottlenecks and avert loop flows, even during peak load periods when it is often more difficult to achieve optimal load flow patterns. The traditional ways to achieve this power flow pattern control is through generation dispatch and power angle regulating transformers. FACTS controllers under development today will also be able to perform in-line control. Section 3.3.6 discusses this further and Section 3.4 compares the relative effectiveness of a hybrid ac / dc system with several existing and future ac-based technologies.

3.3 APPLYING HVDC AND AC TECHNOLOGIES TO MEET SYSTEMS' NEEDS

The structure of this section parallels that of Section 3.2 as it identifies the ac and dc options that might be used to satisfy each of the transmission needs defined in that previous section. The potential roles of HVDC in meeting the needs defined in Section 3.2 are discussed in some depth. This report does not attempt to estimate the size of the future U.S. market for HVDC, but chooses instead to identify and discuss the issues which might make HVDC worthy of consideration in a variety of situations.

Those needs that can be satisfied with ac lines, with or without FACTS enhancement, plus other non-dc altematives are identified and discussed in this section. The FACTS Controllers and "high-phase-order" (HPO) transmission lines mentioned in this section are defined and described in Appendix B. Those transmission needs that can be served by HVDC, either exclusively or alternatively to ac, are discussed at length. In most situations, a decision to use or not use HVDC will be based upon weighing a combination of technical and economic attributes and generally will be application-specific. Since cost is an overriding factor in most instances, Sections 4 and 6 focus on cost issues.

Where appropriate, distinction between "conventional HVDC design" approaches (using traditional line-commutated-converters, LCC) and "advanced" forced-commutated-converter approaches will be cited. Recent developments include active filters which make HVDC somewhat less system specific and reduces space requirements. Outdoor valves [Asplund, 1995] and (series) capacitor commutated converters (CCC) [Jonsson, 1995] also reduce the space requirements. In time these advancements should result in reduced cost to the user. The capacitor-commutated-converter concept will be included in the "conventional" category, although it is a dramatic departure from in-service systems and promises to meet some of the needs the earlier designs cannot satisfy.

In addition to their high costs, HVDC converter applications are limited today by technical issues including:

- the weakness for commutation failures when exposed to ac system faults,
- the demand for reactive power under all operating conditions,
- the impact on ac system performance of large filter capacitors employed to satisfy the reactive power demand, and
- the production of harmonics and the associated complex filtering schemes.

New approaches employing forced-commutated converter techniques are being explored for minimizing or eliminating all of the above disadvantages associated with HVDC. With such advances, HVDC will be applicable in more circumstances than can be accommodated with today's technology. For instance, the need for taps on an HVDC line, small and large, could be accommodated by the future designs more readily than the LCC or CCC schemes.

Advanced forced-commutation-converters (both current source and voltage source) designs being developed today will not be required to meet all of the applications discussed herein. Traditional LCC technology will suffice if the inverter is connected to a strong system. System strength in this context is measured in terms of short-circuit-ratio (SCR); namely the ratio of locally-available short-circuit-capacity (MVA) divided by the HVDC system's MW rating. The CCC approach will permit inverter interfaces to systems with lower SCR than the traditional LCC can accommodate. However, application of HVDC systems employing either LCC or CCC technologies will be more system-specific than applications of future forced-commutation inverters. That is because forced-commutated inverters work well into weak ac networks, including systems with no local generation.

The most promising of forced-commutated inverter approaches is the voltage source converter (VSC) using pulse width modulated switching at relatively high switching frequencies. Converters designed with VSC techniques can operate into zero SCR ac systems, generate reactive power as well as absorb it, control ac voltage independent of active power while producing minimal ac system harmonics. However, the VSC approach is limited today to relatively low voltage applications and losses are still higher than in conventional HVDC converter systems. Expectations are that those limitations will be overcome in time.

Further, the VSC-based HVDC will have a smaller footprint than an LCC or CCC, assuming that high switching frequency schemes are used to minimize the need for harmonic filters. VSC-based HVDC converter stations might eventually achieve the goal of being small, modular, standardized and inexpensive so they can be "dropped in" anywhere like transformers or circuit breakers are today. When that is true, tapping an HVDC line will be routine, as it is today with ac lines.

3.3.1 Integrating Remote Energy Resources

As defined in the prior section, there are two aspects to this category of transmission needs: 1) the exploitation of energy resources already covered by the existing network but are remote from the load and 2) the integration of new resources that require new transmission to connect them to the load directly or to the grid.

In-Network Resources Remote from the Load In-network resources consisting of unused capacity in existing generation facilities and new capacity derived from repowered or new generation sources may not coexist physically with the future loads. Load growth patterns and other factors governing the building and retiring of generation have already resulted in some regions of the country having higher generation capacity margins than other areas. Other incentives for inter-regional power transfers include diversity of load peaks and differences in generating costs. In the latter case, it can be economic to transmit power from a lower-cost region to a higher-cost region, even though the latter may enjoy sufficient or surplus generation capacity. Competition in the generating sector presumably will lessen the differences within regions but may not eliminate the differences between distant regions, at least in the short term.

For instance, the low cost generators in the plains states cannot provide effective competition to the high cost suppliers in east-coast regions unless cost-effective means of transmitting plains-states power to the east coast are found. Since the eastern interconnected network is the largest synchronous network in the U.S., (containing six complete NERC regions and the U.S. portion of NPCC) long inter-regional transmission interties can still be ***intra-network*** transmission ties.

AC Transmission. The existing ac transmission network will carry some of the new energy, to the extent capacity exists and the distances are not too great. More likely, most of the new power must be carried on new or reinforced lines. A large number of possibilities involving ac approaches exist, but the choices will depend upon specifics of each situation. The new circuits probably would be compensated in some way, perhaps with conventional shunt and series capacitors or Static var. Compensators (SVC's). The use of SVC's in the underlying lower voltage network might be required for contingency conditions, at least. Thyristor Controlled Series Capacitors (TCSC) or a Static Series Synchronous Compensator (SSSC) in the new circuits may be justified if subsynchronous resonance (SSR) is a possible threat. A power angle regulating transformer (PAR), SSSC or Unified Power Flow Controller (UPFC) in the new or reinforced line, and/or in adjacent lines, may be required to avoid unwanted parallel (loop) flows.

HVDC Transmission. Where it is possible to build new long-haul transmission between regions of the country, then HVDC could be the best economic choice. HVDC can be less expensive than ac for long distances typical of inter-regional connections. As shown in Section 6, the break-even-distance between HVDC and ac is about 500 miles today (for overhead lines), and will be less as HVDC costs are reduced. As we continue to rely.on our existing ac lines for increasingly greater transfers, using reactive compensation and FACTS for maintaining voltage and stability, losses will increase as well. The projected cost of supplying transmission losses over the life of a line can make HVDC more attractive than ac.

If new rights-of-way cannot be obtained it may be possible to get more power over existing right-of-ways by using HVDC, either in place of existing ac lines or by overbuilding ac lines. Employing appropriate dynamic dc power control, HVDC may also be able to enhance stability, thus the power transfer capability, of the parallel ac system. Never-the-less, ac will still be preferred for many "long-haul" intra-network transmission applications. As noted in Appendix A, about 9,000 miles of new and rebuilt transmission lines are planned for the western U.S. interconnected network (WSCC region) by 2005 ; all of which is ac. If cost-reduced HVDC options were available today, some with "advanced" converter technology, perhaps some of those lines would be planned as HVDC. The choice between HVDC or between the multiple ac alternatives will depend upon the specific circumstances. No general solution can be recommended. A break-even analysis similar to that given in Section 6 must be made to decide between ac and dc.

Remote Energy Resources Out-of-Network or Isolated If one defines a remote area as one that is more than 100 miles from any existing transmission grid, then there are several places in the continental U.S. that qualify as "remote". North central Nebraska, most of Maine, much of Nevada and northern Montana are remote from major transmission system facilities. While the human population (thus electrical loads) may never develop there, future energy sources may be developed in those remote areas. For instance, it is possible to imagine solar plants in Nevada and wind energy farms in Montana, Nebraska and Maine. New coal fields could very likely be remote from existing transmission with adequate capacity so reinforced transmission circuits definitely will be needed for exploiting expanded or new coal resources.

AC Transmission. When new generating plants are located remote from the nearest grid, planners generally consider ac transmission first. For adequate reliability it is typical to use two or more circuits, with switching substations at intermediate points for lines exceeding 200 miles. Overhead ac transmission can be tapped easily to supply intermediate loads along the transmission path or to pick up generation at different locations. In the past, this has been a major advantage enjoyed by ac transmission. However, mutiterminal HVDC is feasible today, and future HVDC transmission technology should make HVDC taps cost-effective.

For long lines where stability is an issue, series compensation , SVC's or both may be necessary to achieve the power density on the corridor. For hydro generation, subsynchronous resonance may not be a problem. However, for thermal generation at the source or near the receiving end of the line, TCSC with SSR mitigation or an SSSC with similar SSR controls may be desired to insure maximum utilization. If there is a weak parallel ac system, SVC's in strategic locations therein may be required for support following disturbances and outages of one of the new circuits. In that case, some of the additional measures discussed above for new sources embedded in existing networks also might be necessary.

High phase order (HPO) lines could also be utilized to integrate a remote generating source. Some underground and/or submarine cable may be necessary, depending upon the available right-of-way. Here again, no general solution can be recommended; a comparison based on technical and economic parameters must be made.

HVDC Transmission. HVDC probably will be the transmission of choice if western coal resources are to serve Midwestern or eastern loads since two asynchronous networks are involved. However, FACTS-enhanced ac alternatives and HVDC will compete for an intra-network delivery of western coal-based energy to western load areas or delivering Midwestern coal-based energy to the eastern coastal region.

Additional imports of large power blocks from Canada will require new transmission, including some HVDC. A growth in hydro energy imports from Quebec would most likely require HVDC. Increased imports from Ontario or other Canadian provinces may be accommodated on new or reinforced (existing) ac lines, but HVDC could be preferred for some of the new capacity. While it probably is a stretch to imagine exploiting new generating sources in Latin America before 2020, such interconnections would surely require new transmission; probably HVDC.

Force-commutated converter technology will have an advantage in some remote energy conversion applications such as variable head/speed hydros and some wind power sets. Additional cost savings may be realized if the concept of the unit-connected hydro generator is developed. In this scheme, the generator-step-up transformer is replaced by the converter transformer, thereby saving the cost of one transformer bank. VSC inverters could be advantageous for low -to-moderate SCR applications, however, CCC and even LCC technology could be applied in many such cases. Converter station cost reduction is necessary for HVDC to gain a substantial share of the future market in this area.

Other potential energy conversion technologies such as fuel cells or photo voltaic converters produce DC power directly. These devices normally produce power at a voltage far below practical transmission voltages. If many of these devices are located in a given area, a low voltage dc system might be used to collect and transmit their power to a central location for conversion to ac. Since the power levels involved in such systems probably will be small and ac interfaces are likely to be weak fringe-areas of the network, voltage-source-converters would be desirable.

In summary, the exploitation of new remote energy resources could be done with ac or dc transmission, with the final choice depending upon both technical and economic factors. Only a detailed, system-specific assessment of the options will determine the outcome.

3.3.2 Increase Power Import Capability Into Congested Load Areas

As noted in Section 3.2, the first choice will be to utilize existing transmission corridors as much as feasible. Where new transmission rights-of-way are required and available, they too must be efficiently utilized. Both ac and dc options will exist in either case, again with the final choice depending upon a mix of technical and economic factors.

Utilization of Existing Transmission Corridors. The transfer of ac power is limited for a variety of reasons; namely thermal constraints, rotor angle stability constraints, steady state minimum and maximum voltage constraints, or voltage stability constraints. Supplying increased loads over existing ac lines will inevitably reach one or more of these limits.

Several non-dc alternatives may apply depending on the specific system requirements. They range from conventional ac system design techniques, to new high phase order and FACTS enhancements.

Conventional AC Solutions. One low-cost approach to increasing capacity might be to retension the existing conductors to permit increased current while maintaining safety clearances. The effective capability of a line sometimes may be increased, without upgrading the physical line, simply by using dynamic current limits instead of fixed current limits based on worst-case thermal conditions. Dynamic current limits closely reflect the actual thermal capability of the line which depends upon weather conditions and the previous level of' loading. They can therefore be used to take full advantage of the actual capacity of the line. R&D into dynamic loading continues and many utilities are gaining experience with the commercially-available monitoring schemes

To the extent they have not been already exploited, limits due to steady state voltage constraints may be relieved by using off-nominal transformer taps, load tap changing voltage regulators, and /or generator excitation control options such as voltage drop compensation. Conventional shunt and series capacitor compensation can also be effective in most cases. Typically these will be mechanically switched to allow for changing system loading conditions.

Reconductoring a line or. redesigning for a higher voltage level will allow more power transfer but the latter may require a wider right-of-way. It may also be possible to over-build existing lines or to add new transmission lines on existing right-of-ways. Magnetic fields may be left unchanged or reduced by reconfiguring the conductors and ground wires. At lower voltage levels compact ac lines may be used so more lines can be put in the same right-of-way. The amount of additional transmission capability that can be obtained by such methods is however limited, and generally can not compete with new ac or dc transmission circuits.

Some lines supplying a load center may be underutilized even while other lines are loaded up to their limits or experience unacceptable voltages. If this is the case limited conventional techniques are available for rerouting the power flows to maximize the total import. Phase angle regulating (PAR) transformers, with or without voltage control load tap changing transformers (LTC's), and/or switched series capacitors may be used for this purpose. In the absence of PAR's, redispatching generation patterns is the only recourse today. Operating constraints for certain outages may also be employed, although they may be viewed as interim solutions only until a permanent "fix" is implemented. In the future, the generation providers may object to such redispatching and operating constraints and will request that a permanent transmission fix be implemented.

FACTS Enhancements: If increased circuit loading creates a potential voltage stability problem then FACTS devices may provide a solution. Depending on the specific configuration of the load-area-in-feed system, thyristor switched or continuously controllable compensation may be particularly useful. One or more SVCs and/or Static Synchronous Compensators (STATCOM) may be effective. If dynamic power flow control is also desired then a UPFC would probably be the better choice. If the load-area-in-feed transmission is of substantial length (the Mead to Los Angeles corridor exceeds 200 miles) then a TCSC might be more cost effective than a UPFC.

Rotor angle (transient or dynamic) stability constraints also may require FACTS to achieve relief Such problems will not normally exist in tightly coupled metropolitan load area systems. However, stability problems do exist on the "East of River" (EOR) transmission interface of the load-area-in-feed for the southern California region. Studies comparing

TCSC, TCPAR (thyristor controlled PAR) or UPFC approaches have been made for that system [Hill, 1992]. No decision was made to incorporate such FACTS controls in the "EOR." interface.

The above methods may increase the amount of power that may be transmitted down an existing ac transmission right-of-way but not to the level that could be obtained using new circuits, ac or HVDC. Back-to-back HVDC can functionally replace the TCPAR or UPFC (see Section 3.3.6) to better manage the capacity that is available, but does not add new transmission capacity by itself

Unconventional AC Approaches: High phase order configurations. Reconfiguring an existing double circuit three phase line into six-phase transmission can also provide more transfer capability for a given right-of-way and distance. The line reactance is reduced by half similar to adding 50% series compensation. The reactance of the additional transformers necessary to interface the six phase line with the remaining three phase network will offset some or all of the reduction in line reactance. For lines over about 20 miles in length, the line reactance reduction is dominant again. Limited experience with six phase transmission has been reported [Brown, 199 1; Stewart, 1992]. The electro magnetic fields (EMF) measured in and adjacent to the ROW can be less than for the lower-rated three phase line, also.

HVDC Options: Direct current transmission could be used to increase the power flow density through existing transmission and subtransmission corridors feeding urban loads or to make additional access possible with modest ROW requirements. An HVDC line can be operated near the conductors' thermal limit, thus permitting higher power capacity than an ac line with the same space requirements. Also, the losses are generally lower for dc.

Overbuilding the ac with dc or converting selected ac circuits to dc would be beneficial in some cases. Reduction in the physical size of HVDC substations will be important for these applications since real estate is scarce and expensive in most urban areas Roof-top installations might be considered for small inverters.

Forced-commutated converters will be particularly attractive in many load-area-supply cases since the reactive power needed by the load, and its automatic control, can be provided by the inverter. This will be particularly important if the load area had lost local generation to retirements. If the area had not enjoyed local generation before, the forced-commutated-converter HVDC could be superior to adding local generation. That is because a HVDC infeed would not increase available short circuit currents as a generator would, thereby permitting continued use of the existing circuit breakers and other similarly-rated equipment. Overall costs of load area resource upgrade might be lower with HVDC infeed.

In some cases existing ac lines may be under-utilized even while other ac line accesses to a city are overloaded. If the under-utilized ac lines are replaced by HVDC the effective increase in power transfer capability may be even greater than the difference between the ac and dc line ratings alone. First, the desired power will be forced to flow on the converted line, that was previously underutilized. Secondly, the parallel ac lines, previously overloaded, can then be better utilized and may even benefit from the using of dc power control to improve stability of the parallel ac or to reroute flows to unload limiting ac circuits following an ac system contingency.

Increased corridor capacity is also possible by over-building an existing ac line with dc on the same towers. Mixing dc and ac on the same towers can cause unique interactive field effects that must be mitigated by design as discussed in Section 8. Placing dc on the same ROW but on separate towers may be feasible due to the smaller width requirements (see Figure 3.1) and may be desiied to minimize the undesirable interaction of the electric fields. Although an expensive option, dc cables may also be installed beneath existing corridors to get more transmission capacity. The ac and dc electric fields would be separated in this case as in the case of separate overhead lines.

Even if VSC-based dc is not required due to low SCR, the lower harmonics of the high-pulse-frequency VSC designs should present less interference with telephone and other communication and protection facilities; an important consideration as more compaction is realized. VSC inverters will make intermediate taps along the dc line more practical than with traditional LCC technology. Taps on a dc line will still be more costly than ac line taps, making the reduction in converter costs vital in these applications.

As in other applications discussed so far, the choice between ac and dc will be made only after detailed assessments of project-specific technical and economic issues. The case for dc overbuilds and conversions is further discussed in Section 5 and the economics of conversion is very encouraging as noted in Section 6.

New Corridors Fur Transmission. Here again both ac and dc options will compete in new transmission circuits on congested in-feeds to dense load areas.

Conventional AC Approaches. Where new overhead ac lines are still permitted, they may be the least cost choice. For 230 kV and below, some compact line designs promise fairly high power densities, with more circuits squeezed on a given ROW. Special conductor arrangements for a double circuit three phase line can exhibit low field effects. Use of shield circuits along the ROW edge in sensitive sections of the ROW may be sufficient to maintain the same level of fields as other lines in the vicinity. Underground and submarine ac cables, although very expensive, may become necessary for infeed to cities. Locating underground cables on railroad ROWs and highway medians may open new corridor opportunities. Provided the distances are compatible with submarine ac cables, perhaps they should be employed more freely along sea coasts and in rivers adjacent to some of our metropolitan load areas.

Where submarine transmission is required of economically justified, ac will have an advantage over dc transmission for short distances and where moderate transmission voltage is required. Submarine ac cables are competitive for lengths up to about 40 km (depends upon voltage) at which length the ac charging requirements limit the transmission of active power.

FACTS-Enhanced AC: New high capacity ac lines similar to the 800 MVA, 138 kV line planned by American Electric Power Corp. [Mehraban, 1996] could be desirable or even necessary in the future. Applied as intended by AEP, such a line equipped with a UPFC, could improve the reliability in the served load area. If used only during contingency conditions to avert overloads on other lesser-rated lines, the excessive losses during those occasions will be justifiable.

Unconventional AC: Six phase lines can provide very high power densities at lower EMF levels than comparable three phase lines. Twelve-phase lines promise even higher densities but they require special (potentially expensive) transformers.

Non-Transmission Alternatives. Energy storage devices such as Super-conducting Magnetic Energy Storage (SMES) and Battery Energy Storage Systems (BESS) might be used in load centers to reduce the peak demand instead of upgrading transmission. Demand side management programs will continue to be used.

HVDC Options. The benefits of dc cited for use in existing corridors can be exploited for new transmission corridors as well. They require narrower ROW than ac lines constructed to traditional three phase designs. The power density of dc is higher and the losses are lower. It should be possible to use overhead or underground HVDC in tight corridors such as railroad right-of-ways and highway median strips where overhead ac would not be feasible or permitted. HVDC control might be used to take maximum advantage of the short term overload capability of cables.

Many of the nations largest and most congested load areas are near the ocean or major rivers. Underwater DC cables might run beneath large rivers or along the coast to bypass congested areas and transmit additional power into city centers. The initial costs and repair costs for submarine cables are high compared to overhead transmission, but may be justified where ROW for overhead transmission is very costly or unavailable.

As in the prior section, low cost converters, preferably with forced commutated converter technology combined with compact substations for a small footprint will be desirable for in-feed to congested, high load density applications. Perhaps the CCC approach will be sufficiently compact and cost-effective in many cases, but the LCC approach, with its large filter banks and limitations in low-SCR situations will not be adequate.

As with exploitation of existing ROWs, both ac and dc options should be evaluated. However, cost-reduced HVDC, especially with advanced inverter technology, could be the best overall solution for meeting our future challenging transmission requirements.

3.3.3 Enhanced Utilization of Bulk Power Networks

Better utilization of the existing transmission and reinforcement of the bulk power networks will be required in the subject time period. Since the bulk power networks are mainly ac transmission facilities, it is reasonable to assume that ac oriented enhancements will be sought wherever possible. New HVDC lines, back-to-back ties, and HVDC networks may fit into a low-overall-cost plan for reinforcing a portion of the US network(s). Economically justified expansions or upgrades of existing HVDC systems may also provide added benefits.

System enhancements for better utilization can be envisioned in four categories : 1) power flow routing and control, 2) improved stability, 3) reduced transmission system losses and 4) new capacity. Power flow routing and control is covered in detail in Section 3.3.6, so the latter two categories are covered here.

Improved Stability of Bulk Power Network. Synchronous machine stability and voltage stability constraints are responsible for many ac transmission bottlenecks. In many such cases, conventional stabiity aids such as power system stabilizers on generator exciters have not been fully exploited so those approaches should be explored before potentially more expensive additions are made to the transmission systems.

AC Transmission Approaches:. On the transmission side, the majority of low-cost , stability enhancements will include adding mechanically-switched series and shunt compensation. Rebuilding and reconductoring, etc. for improved stability are also options. Upgrades to UHV (e.g. 800 kV) class of lines may be appropriate if they can be made environmentally acceptable. An issue associated with high-capacity ac lines (typically 500 kV and up) that must not be overlooked is high voltages during light loading on the lines. Generators are forced to operate under excited and costly reactors are employed in many cases. Today, some of the high voltage circuits are removed from service to eliminate the charging they would otherwise inject into the system. This practice is undesirable in some cases, because it reduces reliability of the system, but will continue to be practiced where it makes sense.

Unconventional AC Approaches: Converting three phase lines to high phase order (HPO) lines may be applicable, but only for lines greater than about 20 miles in length. Only then will the 50% reduction in impedance offset the added reactances of the necessary transformers at the terminals of the HPO line [Kallaur,1982].

FACTS-Enhanced AC Approaches. Application of FACTS enhancements, either in retrofit or in new circuits, will see most beneficial application for stability enhancement. The choices will be TCSC, TCPAR, SVC or STATCOM and combinations of same for the spread-out systems in the western US. The UPFC and SSSC may be more applicable for dealing with stability problems in highly networked systems of the eastern US, although not exclusively.

HVDC Approaches. Strategically located and properly rated and equipped HVDC can provide a measure of stabiity enhancement. The use of dc power modulation to improve the stability of the host ac system is well known. In situations where such control is beneficial to the ac system, the advanced HVDC technology employing forced-commutated-converters will be even more effective due to its ability to provide controlled reactive power support as well.

Where HVDC systems are applied, they also might be used to help control dynamic ac system overvoltages in the immediate locality of the terminals by increasing its reactive power demand. Additionally, ifreducing the power flow set point of the HVDC system can cause an increase in the power flow on parallel ac lines, dynamic over-voltages on the ac system could be reduced. While this scheme could also work to mitigate steady-state overvoltages during light load conditions, the long term economics of such a scheme (namely the increased reactive losses) would need to be examined and compared to the use of switched reactors of some FACTS controller on the ac system.

In general, conventional and FACTS-based ac approaches will prove to be the more cost effective means for providing ac system stability enhancement. While the full cost of a new HVDC system cannot be justified solely on the stabilizing or indirect voltage control it can provide, such control can add value to a new HVDC system if it is first justified on the added capacity it provides..

*Reduce **System** Losses.* Increased utilization of existing ac lines will result in increased loading on some lines. Increased loading means greater losses, which increase as the square of loading. The added losses will erode some of the increased capacity and therefore must not be overlooked.

Conventional & Unconventional AC Approaches: Today, minimum-loss (generator output) dispatches are sometimes employed to lower system losses. Reactive source dispatching is also effective in lowering losses The future transmission operator may require more adjustment of transmission equipment and less generator set point control, since they may be charged for the latter service by generators. Strategically-located FACTS devices that supply and control reactive power such as SVC, STATCOM and UPFC can be invaluable in reducing losses caused by both active and reactive power flows.

Simply forcing active power to flow (using PAR UPFC, etc.) on desired paths rather than allowing flows as dictated by physics, may cause losses to increase; contrary to the objective. Where new lines or reconductoring of existing lines are justified, line designs that emphasize reduced losses should be promoted. This will become routine as the industry's stake holders focus more on their financial bottom line.

HVDC Approaches: To the extent that existing HVDC systems can carry more of the power or be dispatched to reduce overall system losses, they can help release capacity elsewhere on the system to accommodate additional power transfers. However, in-service

HVDC lines typically are operated up to their design capacity to satisfy their owners' capacity and economy energy needs; and are not likely to effect much help in reducing system losses any further than they naturally do already. Where new capacity is required and the distances are great enough, HVDC lines may be favored because they have about 30 % less losses than comparably-rated ac lines. The next section discusses this point further.

New Transmission Capacity: When all incremental improvements have been made to enhance the bulk power network, then new lines must be added to increase the network's capacity.

AC Approaches: As discussed in Section 3.3.1 "Integrating Remote Energy Resources", there are numerous options for adding new transmission capacity, but all face more stringent restrictions than in the past. Whether three phase or high phase order designs are employed, space and other environmental constraints, along with reduced losses and, of course, lowest overall cost will challenge the planner as never before. Some of the new capacity will be achievable without venturing out of existing ROWs but eventually, new routes must be sought. One obvious example is a tap and new line to serve an area not previously served at transmission voltage.

AC lines lend themselves naturally to network configurations and taps. The need for added taps on the current transmission systems will require substation space and equipment, but no new technology is required. More compact substations and lower loss / reduced-cost transformers will be advisable, if not mandated by competitive pressures. Here again environmental and aesthetic issues may dictate more costly overhead and / or underground solutions.

HVDC Approaches: *New* cost-reduced HVDC facilities will feature increased capabilities as well more attractive converter costs so they should compete favorably with ac alternatives. Of course this is only for line lengths exceeding the "break-even distance" (see Figure 3.2 and Section 6) or where interconnection of asynchronous networks is involved. Both the installed cost of HVDC converter station facilities and converter losses must continue to decline with improved HVDC converter designs for HVDC to be competitive.

If the reduced cost trends assumed in this report (Section 4), HVDC will become even more competitive with ac than it is today for long distances, and should be more competitive for shorter distances in the future. Section 6 discusses the break-even distance between ac and dc lines, especially as it may be impacted if ac line loadings are pushed nearer to the thermal limits than is done today.

Replacing or expanding some of today's mature HVDC systems could be a cost-effective means of increasing the capability of the transmission system. The Pacific Northwest Inter-tie expansion is a good example of how an existing line may be able to accommodate increased converter ratings. The advent of adaptive ac and dc filters will provide an opportunity to improve filter performance, perhaps reduce losses, and provide space on site for expansion.

By adding an appropriately-rated VSC to an existing facility, it may be possible to eliminate at least some of the capacitors in the original system. This alone may provide the space required for the expansion. Preliminary studies project 2000,1995] by Western Area Power Administration engineers have shown that the capacity of the Miles City Converter Station back-to-back facility could be increased by approximately 50% with little modification to the ac systems, provided a VSC was utilized for the expansion.

Existing HVDC lines often traverse remote areas where there is limited or no ac transmission. Extending the ac system to supply local load in these areas may be very costly, so tapped power off of existing HVDC lines, if cost effective, could be very valuable. In other cases HVDC may pass over well developed ac systems. Here an I-IVDC tap in the right place' may unload critical ac circuits, improve reliability and/or help correct voltage problems. However, in many cases these local loads are small compared to the total HVDC transmission. Today, small HVDC taps are expensive and technically challenging and therefore are rarely used. Lower cost converters employing improved VSC technology could make such taps feasible.

To reduce the number of dc taps for serving intermediate ac loads, one might use the scheme suggested by Woodford [Woodford, 1994] which employs an insulated shield wire of the dc line as a low voltage (50 - 150 kV) subtransmission or distribution circuit to serve small intermediate loads. This could be a single-wire-earth-return ac (single phase) circuit and would be fed from the nearest dc to ac tap. Serving three phase loads would require special transformer connections at the load point. Overbuilding or under building a full three phase ac distribution line might be preferred in many areas, since continuous use of earth as a conductor is disallowed by the National Electric Safety Codes at this time.

3.3.4 Interchange Energy Between Asynchronous Networks

Today there are four asynchronous networks within the interconnected systems of the US and Canada. Future opportunities to interconnect two or more of the four asynchronous networks for inter-regional transfers will certainly arise. Interconnecting with ac is possible but generally is much more costly than with dc. HVDC continues to be more cost effective than ac for such interconnections, even with FACTS enhancements. Accordingly, there could be new or additional opportunities for interconnection between the following asynchronous regions:

US and Hydro Quebec
US and Mexico
Eastern US/Canada to Western US/Canada
Texas and Eastern US and/or western US
US and the Caribbean Islands
Between US-owned Islands (Hawaii, Southeast Alaska, etc.)
Isolated systems in Alaska and Western US/ Canada network

New asynchronous systems may be created within the continental US in the future for the reasons cited below. If separation is chosen, HVDC would be necessary to exchange energy between the systems. Some trends that could result in new asynchronous interconnections are:

- Insufficient synchronizing capacity between portions of a network
- Different power quality standards in parts of a network,
- Legal or regulatory aspects of asynchronous interconnections,
- Diminishing returns from large interconnections.

Insufficient Synchronizing Capacity. The synchronizing capability of selected ac transmission inter&es within contiguous networks may deteriorate over time to unacceptable levels requiring either large, expensive ac system reinforcements or separation. It is possible that the current trend to supply growing loads with local gas-fired generation could reach a point where there is insufficient synchronizing capacity across the interface.

Two ac systems cannot be tied together synchronously by a very weak ac interconnection. The interconnection must be able to keep the systems synchronized even if the level of transfer between the systems is small. The minimum transmission capacity needed to synchronously connect two systems properly is approximately 10% of the peak generating capacity of the smaller system.

AC Approaches: The ac lines comprising subject the interface could be reinforced with a combination of additional circuits and FACTS devices on existing lines. Series capacitors or their electronic counterparts (UPFC or SSSC) may be necessary to reduce the effective impedance and maintain synchronism. The cost of such reinforcements could be substantial, and continued growth of the generation would require additional reinforcements in time. Eventually, small deviations in frequency on the two networks would cause an unacceptable angle across the ac link leading to an uncontrollable power overload of the link.

HVDC Approaches: In such cases, the least cost mitigation might to operate portions of the network separate except for HVDC interconnections for power exchange. Section 8.2 discusses two examples where this is possible, in time. HVDC based on conventional LCC or CCC technology probably will apply in many situations, but VSC designs will provide maximum flexibility. Many of the desired inter-tie locations will be fringe areas of the networks, exhiiiting "weak" system characteristics, for which the VSC approach will be ideal. The Project 2000 example cited in the previous section is a good example of such a situation. This split-with-dc-tie approach could also require upgrading of intertie capacity in time, thus this issue will require detailed assessment of the relative cost/benefit projections on a case-specific basis.

Perhaps a hybrid approach with FACTS-enhanced ac plus new special-purpose back-to-back dc interties equipped with aggressive stabilizing power control may insure the stability of an ac interconnection. The special-purpose dc link would control interchanged power in response to angular differences across the ac interties. The angle measurements might be communicated to the dc link via satellite as recommended by various investigators [Adapa, 1996; Mittelstadt, 1996; Street, 1994]. The power transferred by the dc link would be proportional to the angular difference, making it provide synchronizing strength to the hybrid interconnection. Further studies of this concept are necessary on a case-specific basis. The need to simulate very large systems connected by yet-to-be-modeled hybrid schemes will be challenging, but the pay-off could be substantial.

Different Power Quality /Reliability Needs. Power quality issues generally are addressed at the distribution level, but Power quality problems that emanate from, or are transported by, the transmission system should be "fixed" at that level. Voltage dips, sags, flicker and harmonics are the main problems. Interconnecting the 60 Hz. main grid with subsystems that operate at other frequencies are not be possible with straight forward ac connections. Fortunately, those cases will be rare and special enough to justify frequency converters or dc links.

AC Approaches: Interconnecting areas with the same frequency but different power quality requirements (most likely related to harmonics) should be achievable with ac by utilizing appropriate harmonic filters. Recent developments of adaptive harmonic filters for application at subtransmission and distribution voltage levels hold promise for such instances. High voltage application of adaptive filters would be desirable in areas where large harmonic-generating industrial loads are served directly from the high voltage system. An example of this is in the Pacific North West where large aluminum smelting plants are served directly from the 500 kV grid. The harmonics spread over a very large area when they are injected at such high voltages.

HVDC Approaches: With the unbundling of the power industry will come the need to tailor power quality and reliability to individual consumer needs. A consumer that does not need precise frequency regulation, voltage regulation, high reliability or who can tolerate a high level of harmonics would then expect to pay less than a user who has more demanding requirements. Some industrial and large commercial consumers are already exploiting these opportunities to obtain low cost service. Some large consumers with privately-owned systems, such as railroads paper mills and mining operations, may need to operate at frequencies other than 60 hertz.

While these may not constitute a large percentage of the nation's load, such "independent" power systems will demand "special" interface conditions. These "independent" systems could be tied to the grid or to each other by direct current . . perhaps at subtransmission or distribution voltage levels... to exchange power but still limit their dependence on others. Since such applications will be "premium" connections to cater to special power system quality and reliability requirements, the VSC approach will be desirable.

Regulatory Aspects to Asynchronous Operation. ERCOT (Electric Reliability Council of Texas) members are exempt from federal regulations (FERC) since they engage only in intrastate power exchanges. By using only asynchronous ties to utilities outside ERCOT in the past, they have maintained that exempt status until now. The Energy Policy Act of 1992 gave FERC power to mandate ERCOT to provide open access to their network to others, although FERC has not yet chosen to exercise that authority. The lack of transmission capacity is no excuse for denying access so FERC could demand additional ties between ERCOT members and adjacent utilities not synchronously interconnected. More HVDC ties between ERCOT and their neighbors could result in time.

In other parts of the U.S., the current move toward competition is leading to mergers, some of which will involve parties in asynchronous networks. A typical case for merger cites the economy of scale as a benefit leading to reduced consumer rates. The economy of scale argument can only be defended if energy exchanges between the merging parties can be realized. If the 'merging parties are within the same interconnected network, the criterion might be met, even if the power must flow through lines owned by other companies. If the two merging parties serve areas not yet interconnected by ac or dc lines, then the parties must interconnect with HVDC.

The prior existence of HVDC ties between asynchronous networks may pass the test if the merging companies can obtain use of those ties for exchange of energy. However, many of those ties are fully utilized by the owners. Therefore, conditions would mandate that new HVDC interconnections be established between networks so the new combined company was able to realize the benefit of energy exchanges for economy or capacity. System specific requirements will dictate whether or not VSC technology must be incorporated in such ties, but VSC designs will be preferred for flexibility of placement the interconnected systems.

Diminishing Returns from Large Interconnection. Large interconnected power grids have evolved in the US for the following reasons:

better frequency control
increased reliability
savings from energy and capacity interchange
economics of scale (e.g.,use of large generators)

However as the individual power grids grow Iarger, these advantages may reach a point of diminishing returns. Interconnection also creates certain disadvantages. Loop flows can result in additional losses and overloaded circuits. Cascading outages may occur where a local disturbance leads to a collapse of the entire system. On the eastern interconnection, sustained oscillations have been observed on generating units in the northern areas of the Northeast Power Coordinating Council area upon opening one terminal of a 500 kV ac line in the Southeast Electric Reliability Council. The western ac interconnection has experienced numerous cascading outages because of its expansiveness and heavy line loadings.

AC Approach: Such problems might be controlled or mitigated through the prudent placement of conventional and FACTS controls. Loop flows can be controlled with PARs or UPFCs. Unwanted system oscillations may be controlled through better (coordinated) utilization of power system stabilizers on generating units, and the use of SVCs, TCSCs, or UPFCs in the networks. The potential for cascading outages can be limited through the coordinated use of FACTS devices to control power transfers following contingencies on the ac system.

While these recommendations sound straight-forward, they are not easy to design and implement. One large concern in dealing with the increased size of existing interconnections is the increasing difficulty of simulating and developing operating actions for the ever increasing number of contingencies and system conditions. Perhaps those tasks would be simpler and produce more predictable results if the large networks were subdivided into more manageable ones with tightly controlled interfaces.

HVDC Approaches: *One* might find that there is a maximum grid size beyond which the disadvantages of interconnection outweigh the advantages. With HVDC interconnection the amount that one asynchronous region is influenced by another is limited to the amount of power which is transferred. HVDC interconnection preserves most of the advantages of synchronous interconnection and limits some of the disadvantages. Again VSC designs will provide maximum flexibility, but LCC and / CCC designs could suffice in many cases.

3.3.5 Serving Isolated Load Areas

As noted in Section 3.2.5, there are two aspects of this need: 1) serving physical islands and 2) serving radially fed remote load areas with intermittent or no local generation. Some of the islands and remote areas of Alaska are examples of physical islands. Other physical islands off the coast of the U.S. may experience load growth sufficient to require new or upgraded cable connections to the mainland. However, the load area need not be a physical island. The load might be within a network but connected by a single radial ac circuit with lower than desired reliability. As load increases or reliability concerns become critical, the single ac circuit could become inadequate

Physical Island Loads and Systems. Local generation is often the only option for supplying an isolated system. If the island is near the mainland of US or Canada, an ac or dc cable interconnection to resources on the mainland can be very valuable. The cable interconnection will normally provide better reliability, frequency control and voltage regulation than isolated operation. Imported power is also likely to be less expensive than local generation. Typically, the overhead line portion of the link would not be limiting. The required length of the submarine cable and the needed power capacity will determine whether ac is feasible or dc is required.

At this time, the only dc submarine cable in North America is the Vancouver Island cable in British Columbia, Canada In contrast, there are many ac cable connections to islands very near the US coast line. One example is Nantucket Island, off the coast of Cape Cod, Massachusetts. Nantucket Electric opted for a cable from the mainland rather than continued reliance on aging diesel generators. In that instance, the moderate load involved and the 26 mile distance permitted use of 46 kV submarine ac cable. However, if the island load had been large enough to require 345 kV, or greater voltage for the interconnection, that distance would have been too great for ac cable. High voltage ac cables must be limited to short lengths to avoid excessive charging currents from consuming the capacity for active power transfer.

AC Option: If the needed capacity is small then low voltage ac cables may serve the purpose. If the capacity is large, a large number of low voltage cables in parallel may be justified. However, the distance may determine whether ac cables are feasible at all. The problem here is that the charging current can totally consume the current capacity of the cable leaving no room for active power. For instance, one study (Section 7) revealed that a 345 kV submarine cable is limited to about 40 km (24 miles) due to this problem. No FACTS device contemplated today will remedy this problem. The only possible solution would be underwater switching stations with submarine reactors. The cost of such submarine facilities, if they were available, probably would make HVDC more attractive.

The power quality and voltage support requirements at the load would also have a bearing on the cost of the ac alternative. Some form of controllable reactive compensation might be needed at the load-end of the cable, unless some local generation supplies this service or the load itself is equipped with such facilities. Some industrial and commercial customers might justify the added expense of power quality and voltage control devices, but normal residential customers would not. Unless a local generating source will continuously provide this "service", the cost of reactive compensation must be included in the *ac* alternative. For such an application, an SVC or STATCOM - in combination with conventional switched capacitors to minimize cost - could be appropriate.

DC *Option:* As noted above, there is a combination of voltage level and cable length beyond which ac cable is simply not feasible because of the charging current of the cable. For longer submarine cables dc is the only option. HVDC cable feeds to islands also have limitations with today's HVDC technology. That is, the traditional line commutated converter cannot feed a "dead" ac system; meaning one with no ac voltage source. In cases where that has been encountered, a synchronous compensator must be located at the inverter end on the island to provide that ac source. Future force-commutated-converter systems will not suffer that expensive disadvantage.

In case where the major advantage of an interconnection to the mainland grid is a combination of greater reliability, better frequency control, and better voltage regulation, the future "advanced-technology" HVDC interconnection could be more cost effective than ac, even for short cable distances. Local on-island voltage and frequency control could be satisfied naturally by a voltage-source inverter. Since most island service situations will require operating, at least part time, with little or no local generation, the VSC design system will most applicable.

Improved Reliability of Radial Lines. The specific case of interest here is a load area fed by a single circuit ac line. There are many small load areas located on the fringes of the bulk power network that are served by a single-circuit ac line of modest voltage, say 115 kV, 138 kV or 161 kV. In many cases, the reliability of the line may become inadequate for the needs of the customers, or load growth may justify "firm" supply to the area.

AC Approach: A second circuit is one possible way to improve the reliability. However, a lack of available ROW for the second circuit could rule this option out. Further, no FACTS enhancement can improve the reliability of the single circuit. Alternatively, the ac line might be operated with a high impedance ground so that the line would not trip for most single phase faults. Protection and personnel safety requirements as dictated by the National Electric Safety Code must be carefully considered in this approach, but it should work. The power quality may be unacceptable to the customers served off the circuit, unless they employ special equipment to isolate their computers and other electronic loads from the inevitable transients possible with this scheme.

DC Approach: The conversion of the existing ac line to a bipolar dc line is one way of achieving two-circuit reliability. Of course, the viabiity of this approach will depend upon the reliability criterion used by the served utility. If loss of a tower is their criterion then nothing is gained by modifying the operation of the single ac line as described, or converting to dc on the same towers. Only a new line on a separate towers would meet the criterion .

Absent the need for separate towers, the overall reliability of such a design would still need to be examined to ascertain the impact of converter station equipment on the total reliabiity. However, it seems that a bipolar HVDC line with metallic return (utiliig the third ac conductors) should be more reliable than a single circuit radial ac connection. For example, a line to ground fault (the most common type) will interrupt completely the ac transmission but will only interrupt half (one pole) of the dc transmission.

If the HVDC is designed for sufficient overload duty, and is less than fully loaded initially, the power on the remaining pole can be increased quickly so a portion or all of this interruption is only momentary. Since a converted line will be capable of carrying nearly the thermal rating of the conductors, that is about 3 times surge impedance load for the ac line, there should be substantial temporary overload capability. This assumes that converters are sized to exploit this advantage and that the load does not increase immediately to consume all the added capability.

Therefore, HVDC could be used to upgrade reliability where load is presently connected radially by a single circuit ac line. The existing ac line could be converted to bipolar dc (with metallic neutral return) simply by changing the insulator strings of the ac line. In addition to improving the reliability, the MW capacity could be increased. The amount of increase would depend upon the voltage and current ratings of the original conductors and the losses that can be accepted, but a conservative estimate is at least 50 %. Advanced converter technology like the VSC-based dc would be required unless the load area has local generation or a synchronous compensator they can run continuously for voltage and frequency regulation.

3.3.6 Power Flow Routing and Control

The control of power flow routing will increase in importance in the future competitive environment. As the industry embraces competition, the transmission operators will use power flow (pattern) control to gain a competitive advantage for themselves and their clients. Prevailing market pressures appear to favor a "free market" environment with transmission charges negotiable on an hourly basis. Therefore, the future needs to accommodate both wholesale and retail wheeling contracts that change from hour-to-hour, will mandate more flexible control of the transmission such as that provided by HVDC and FACTS controllers. Similarly, more wide-spread use of controlled reactive power will be vital to optimize transmission utilization.

Conventional AC Approaches: *Slow acting* active power flow control will continue to be provided by phase angle regulators, generation re-dispatch, and where effective, switched series capacitors and reactors. Generation redispatch as a routine means of flow control will probably become less popular as transmission ownership and operation is separated from generation. Generation redispatch may be treated as an "ancillary"service available to the transmission providers for a fee. Faced with a fee, the transmission provider may opt to handle overloads simply by switching out the overloaded circuits or devices, as is often done today.

Today, control of steady state reactive power flows is provided by mechanically switched shunt compensation, tap changing transformers and generator excitation control. These devices also have a second order effect on active power flow. Their use will increase as their need becomes more acute.

High-tech AC Approaches. To the extent they are strategically located, energy storage systems such as advanced pumped hydro, SMES and BESS can be used for rapid contingency MW flow control and some steady state MW flow management. These will also have a second order effect on reactive power flow. These costly schemes probably will be dedicated to contingency overload mitigation like the intended use of AEP's UPFC-augmented high capacity line [Mehraban,1996]. For highly networked systems, the UPFC, SSSC or the Interphase Power Controller (IPC) may be the best choice for rapid control of MW and/or MVAR. For systems with long lines, the TCSC, and/ or TCPAR in combination or IPC probably will be more effective than the UPFC ; see Section 3.4 for a comparison between flow-control techniques.

HVDC Approaches: Strategically located back-to-back HVDC and dc lines, some arranged in multi terminal comigurations, could offer a degree of power flow (pattern) control in the future transmission system. As converter costs come down, it should justify incorporation of substantial overload capacity in HVDC systems so they can be used to deploy spinning reserve in a better way than possible today. Voltage source converters also will make a greater range of var control possible.

Advanced technology HVDC should permit viable HVDC networks. HVDC mesh networks have not been built because of the high cost of converters, lack of a proven dc breaker and the complexity of control. Reliable dc breakers, if they are really needed, could be built although they are likely to be more expensive than conventional ac breakers. Some of the dc network control problems would be eliminated with forced commutated circuit schemes. With lower cost converters HVDC networks might therefore become practical. Such systems could provide added capacity as well as a welcomed degree of flow control.

The eight existing back-to-back HVDC ties in the US interconnect asynchronous networks; that is, none are entirely internal to any given network. Functionally, such ties also could be used within networks to provide the role that PAR transformers do today. Such a flow-control application of the back-to-back dc could be more effective than the traditional PAR (see Section 3.3.6) since the latter's range and effectiveness is partially dictated by the impedance of the parallel ac lines and is limited to avoid excess voltage on the line-side of the regulating winding. Selected use of dc in underground networks would also be valuable for similar reasons. However, this potential advantage of controlled dc, like most of the above-mentioned possible benefits, is system-specific and must be evaluated on a case-by-case basis.

3.4 Power Flow Control, with AC or DC

The development of FACTS technologies is timely as we face a restructured power industry where the transmission system operator must accomodate competition in the generation and distribution sectors. Indeed, the transmission operators will also need to as lexible as possible and capability of power flow control will be vital in the future.

3.4.1 The Need For Control

The control of steady-state power flow is required to meet interchange contracts, to avoid bottlenecks and "loop flows". It is generally accomplished today using generation dispatch and power angle regulating transformers. Existing HVDC lines that are strategically located in series or in parallel with key ac lines can help establish the desired power flow patterns. This assumes, ofcourse, that a certain amount of the HVDC line's capacity is held in reserve for this purpose.

Series connected FACTS controllers are advanced power flow control devices. Usually, these devices are employed for their dynamic control capabilities, with steady-state flow control a secondary purpose. This report summarizes the power control capabilities of an ac line equipped alternatively with one of the following five schemes:

-Unified Power Flow Controller (UPFC),
-Static Synchronous Series Controller (SSSC), and
-Power angle regulator (PAR) with or without power electronic switches,
-Series capacitors, mechanically switched or thyristor-controlled,
-Back-to-back HVDC.

Only the steady-state control is analyzed, and then using only theoretical concepts. The treatment is brief but there are many good papers that contain detail treatments of the steady state and dynamic capabilities.

3.4.2 Prior Works

Several excellent papers have laid the foundation for the comparison provided herein. Gyugyi published the basic physics and operating strategy of the Unified Power Flow Controller (UPFC) in reference [Gyugi, 1994] and coauthored reference [Gyugi, 1995] wherein the basic power flow control relationships for the UPFC were detailed in theoretical terms. The latter reference compared the UPFC with thyristor-controlled series capacitors and the thy&or-controlled power angle regulator. A derivative of the UPFC utilizing only the series connected inverter of the UPFC, namely a SSSC, was analyzed by Ramey, Nelson, et al [Ramey, 1996] and is revisited in this report. The authors of that paper compared the SSSC with the UPFC, series capacitors and power angle regulator (PAR). Gyugyi, Schauder and Sen made a critical comparison of the SSSC with series capacitors in a recent IEEE paper [Gyugi, 1996].

Those earlier works ignored some practical constraints - specifically, the practical limits on line voltage and thermal flow limits - which are considered in this report. This report extends the basic system modeling of those earlier works, leaving the more complete modeling of the ac system effects using power flow and stability programs to system-specific examples. Other published works have progressively introduced more realistic models of the devices and the ac network in which they are embedded. They modeled the subject devices in power flow and dynamic simulation programs [Henderson, 1995; Gyugi, 1996] with varying degrees of device modeling sophistication.

3.4.3 Basis of Comparison

Following the examples cited in [Ramey,1996], a single line embedded in a strong ac network with a power controlling element at one end is analyzed. Five competing approaches for the power controlling element are studied to determine the relative ability for regulating the steady-state power in the line. The system in Figure 3.3 is the subject of the comparison. To keep the analysis simple, the two line terminations are assumed to be "infinite buses" in that both the magnitudes and phase angle separation of voltage $\mathbf{V_S}$ and $\mathbf{V_R}$ are fixed. This situation could be approached in practice by a low voltage transmission line (115 kV, e.g.) embedded in the tightly-knit ac network of the eastern U.S. interconnection. This assumption was made in the references also, thereby making this analysis an extension of those works.

Implicitly assumed by this analysis is that any change in power on the controlled line is matched by dispatch adjustments in the two connected areas, otherwise the incremental power will simply circulate (create a loop flow) in the parallel system. That is, the initial action by an in-line power controller will cause a circulating current in the parallel paths. Assuming the called - for change in power flow in the controlled line is followed by an adjustment in dispatch to restore net flow to its initial level, the circulating current will cease and the desired power-sharing will be acheived. The intermediate power flows (including circulating current effects) are not considered in this analysis, but are the subject of other publications. The comparison is made in terms of the controllability of the received active power $\mathbf{P_R}$ and the accompanying variation of receiving-end reactive flow, $\mathbf{Q_R}$. The arrows in Figure 3.3 define positive $\mathbf{P_R}$ and $\mathbf{Q_R}$.

Two sample lines are analyzed; a 50 mile, 230 kV line as analyzed in [Ramey, 1996], and a 150 mile line of any voltage class. The equations for $\mathbf{P_R}$ and $\mathbf{Q_R}$ for each device/line combination were derived and "programmed" in Microsoft Excel to derive the $\mathbf{P_R}$-vs-$\mathbf{Q_R}$ plots from which the estimated power control range can be inferred. The equations are derived in Appendix C.

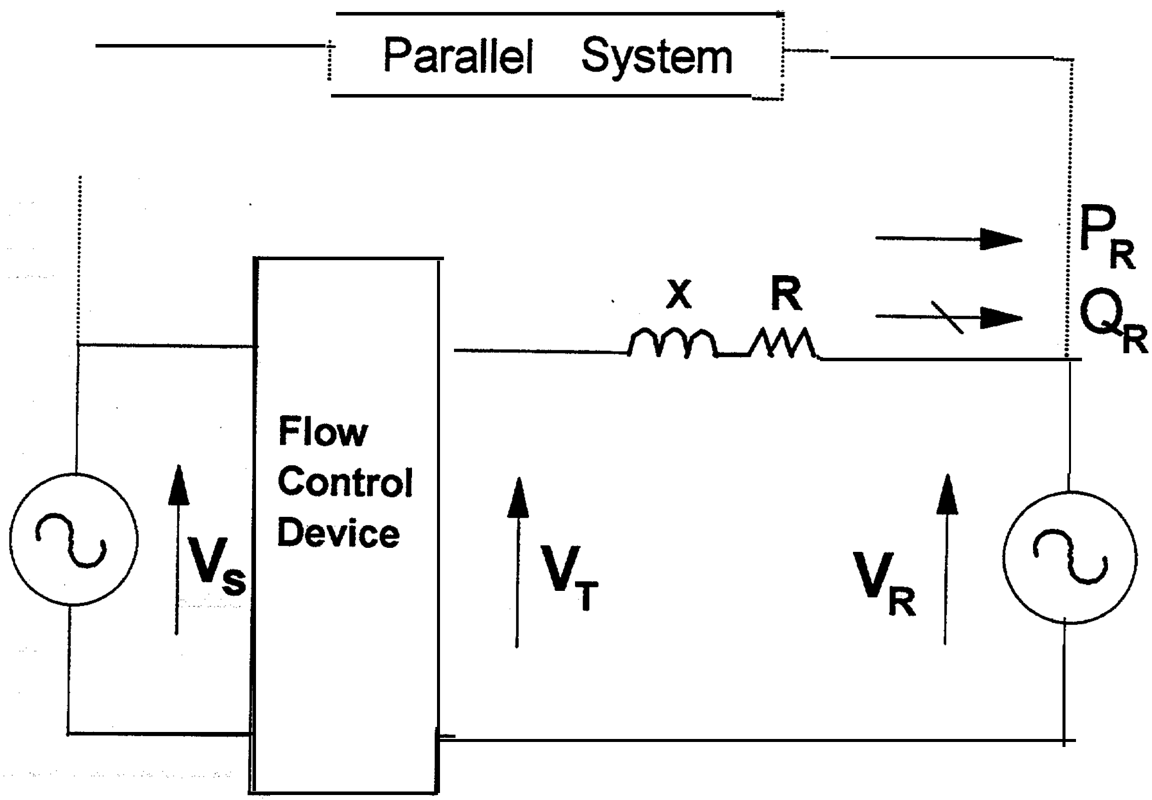


Figure 3.3 System Studied

3.4.4 Unified Power Flow Control (UPFC)

Figure 3.4(a) shows a simplified schematic of the UPFC which is composed of two voltage-source inverters connected on the dc side. Figure 3.4 (b) illustrates a functional representation of the UPFC in a line as used in [Gyugi, 1995] and in this analysis. The analysis evaluates how the series inverter/winding acts to control active power flow.

The utilization of the shunt connected inverter (STATCOM) for reactive power or voltage control at the point of insertion is not modeled per se. However, the analysis does apply constraints on the magnitude of inserted voltage $\mathbf{V_i}$ to avoid making the line-side voltage, $\mathbf{V_T}$, too large or too small for practical steady-state operation. These constraints were not observed in the reference works. The terms and the operating strategy of the UPFC are defined with the help of Figure 3 .5.

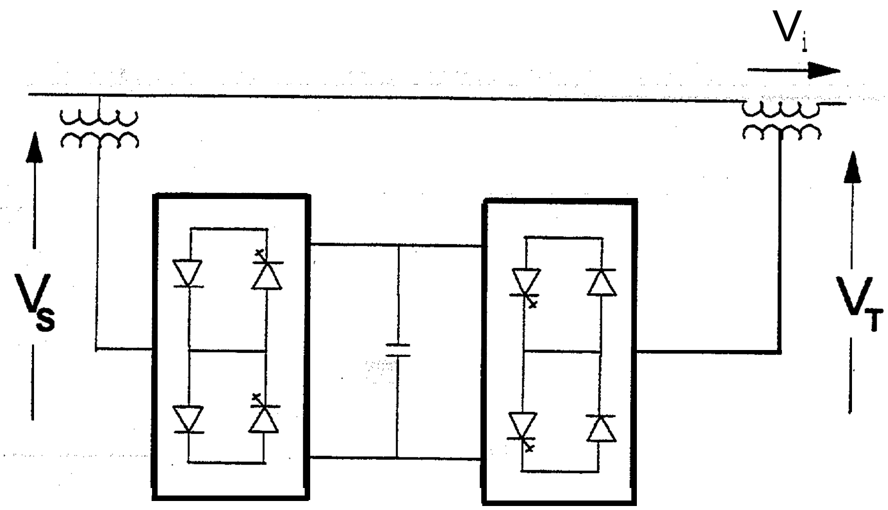
The UPFC produces a voltage $\mathbf{V_i}$ in the series winding which adds to the fixed source voltage $\mathbf{V_S}$, in a phasor sense, to produce a voltage $\mathbf{V_T}$ on the line-side of the UPFC as illustrated in Figure 3.5. The magnitude of $\mathbf{V_i}$ and its phase relationship with respect to $\mathbf{V_S}$, namely the angle p (rho), are both adjustable. That is, if the source voltage is lower than desired, $\mathbf{V_i}$ can be chosen such that $|\mathbf{V_T}|$ is the desired magnitude. Further, if the power transferred on the line (which is determined by the angle between $\mathbf{V_S}$ and $\mathbf{V_R}$) is different from the desired

power, then $|\mathbf{V_i}|$ and rho can be chosen to make the angle between $\mathbf{V_T}$ and $\mathbf{V_R}$ consistent with the desiied power. In other words, the UPFC acts like a phase angle regulating (PAR) transformer in the latter case.

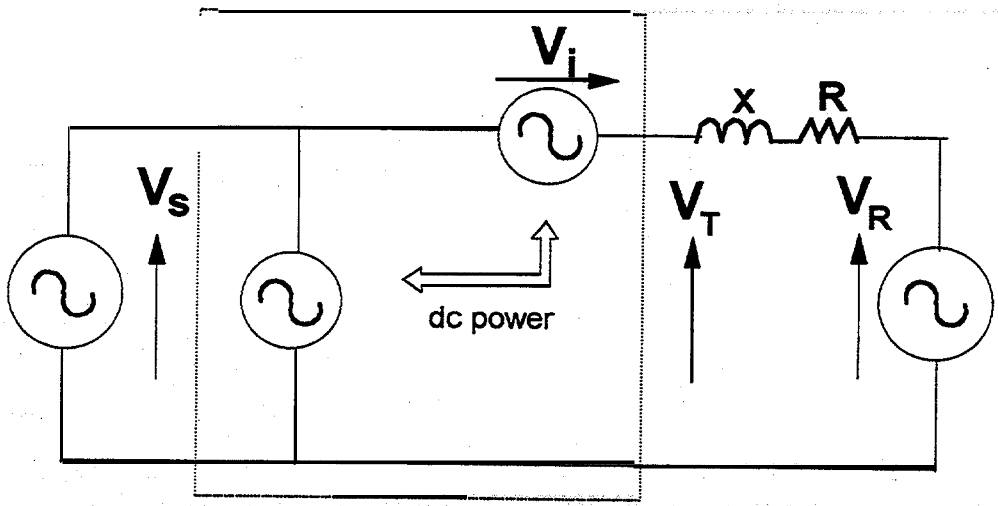
Consider the numerical example used in [Ramey, 1996] as an initial illustration:

50 mile, 230 kV line
Line impedance = 0.005+j 0.05 per unit on 100 MVA base.
Voltages $\mathbf{V_S}$ and $\mathbf{V_R}$ given as rated (1 p.u.)
$\mathbf{V_S}$ leading $\mathbf{V_R}$ by $\delta = 10$ degrees
Complex power (w/o UPFC) , So = Po +j Qo = 3.4-j 0.64 p.u.
Maximum $\mathbf{V_i}$ (rating of series winding) = 0.25 p.u. on 230 kV base

Fixing the inserted voltage at 0.25 p.u. and rotating it (rho) through 360 degrees, the plot of P_R-vs-Q_R yields a circle centered at Po+jQo shown in Figure 3.6(a). This result was reported by Ramey, Nelson et al in [Ramey, 1996]. Any operating point within the circle should be achievable with the chosen UPFC rating. However, at almost all values of rho except those very near 90 and 270 degrees, the magnitude of $\mathbf{V_T}$ is outside of the typical operating range of 0.95 to 1.05 p.u.



(a) - UPFC One-Line Representation



(b) - Functional Model of UPFC

Figure 3.4 One Line Diagram and Model of UPFC

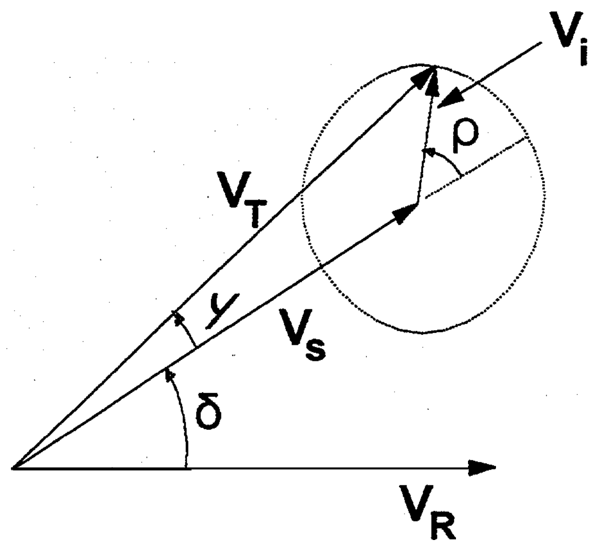
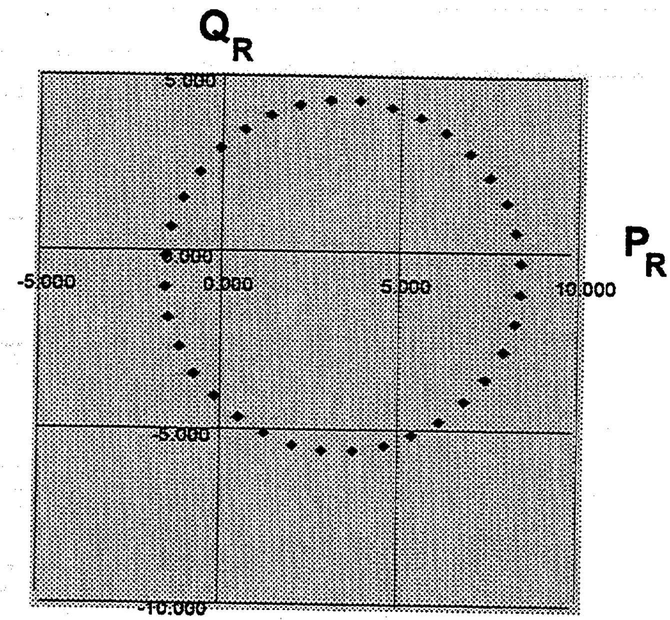


Figure 3.5 Voltage Phasor Diagram for UPFC Operation

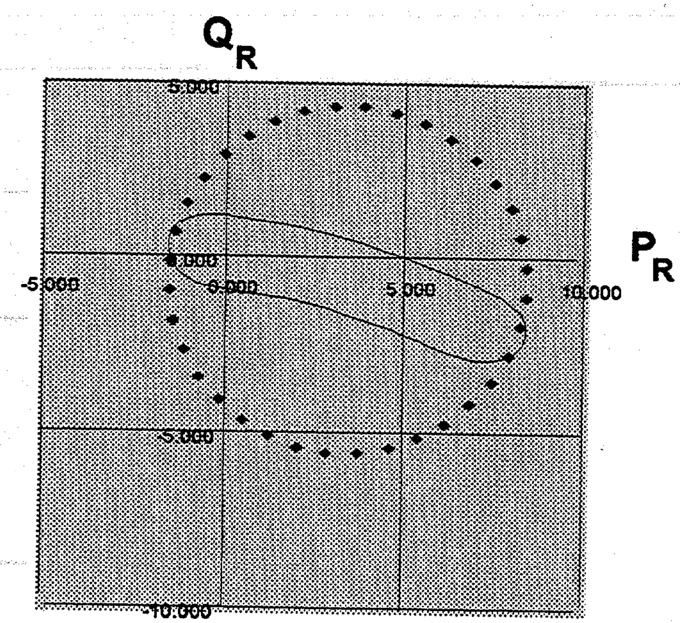
Constraining the magnitude of V_i such that the magnitude of V_T is constrained between 0.95 p.u. and 1.05 p.u., the plot of P_R-vs-Q_R becomes a "collapsed circle" or tubular shape as seen in Figure 3.6 (b). Calculating the unconstrained UPFC circles for load angles: $\delta = 0$, 30 ,60 and 84 degrees, yields the sequence of plots in Figure 3.7(a). The maximum power occurs at 84 degrees instead of 90 degrees due to the presence of line resistance. Constraining the magnitude Of V_i to keep $|V_T|$ between 0.95 and 1.05 p.u. yields the sequence of tubular shapes in Figure 3.7(b). One can conclude from that figure that the range of P_R control diminishes at high initial load angles. For a load angle of zero the power control range was $\pm$ 500 MW whereas that control range shrinks to about $\pm$ 100 MW at 84 degrees.

Further, steady-state operation of typical 230 kV lines are thermally limited to about 400 MW. That means that any P_R value beyond 400 MW (+or -) is unavailable. Applying that constraint to the characteristic in Figure 3.6 (b) yields the truncated shape in Figure 3.8 (a). The natural control range is $\pm$ 500 MW about the initial operating power dictated by the outside system (UPFC off line) except when truncated by thermal limits.

The range of dynamic control achievable with the UPFC is much greater since excursions of $|V_T|$ to 0.8 and 1.15 p.u. are tolerable for fractions of a second, and synchronizing power swings out to angles exceeding 90 degrees are possible. To a very crude first approximation, the theoretical dynamic range afforded with the chosen UPFC rating ($V_i = \pm 0.25$ p.u.) is illustrated in Figure 3.8 (b). assuming a dynamic excursion of load angle, 6, from 10 degrees to 60 degrees.



(a) - UPFC Characteristic; V_i unconstrained



(b) - UPFC Characteristic with V_i constrained

Figure 3.6 UPFC Characteristic - With and Without Constraint on Inserted Voltage

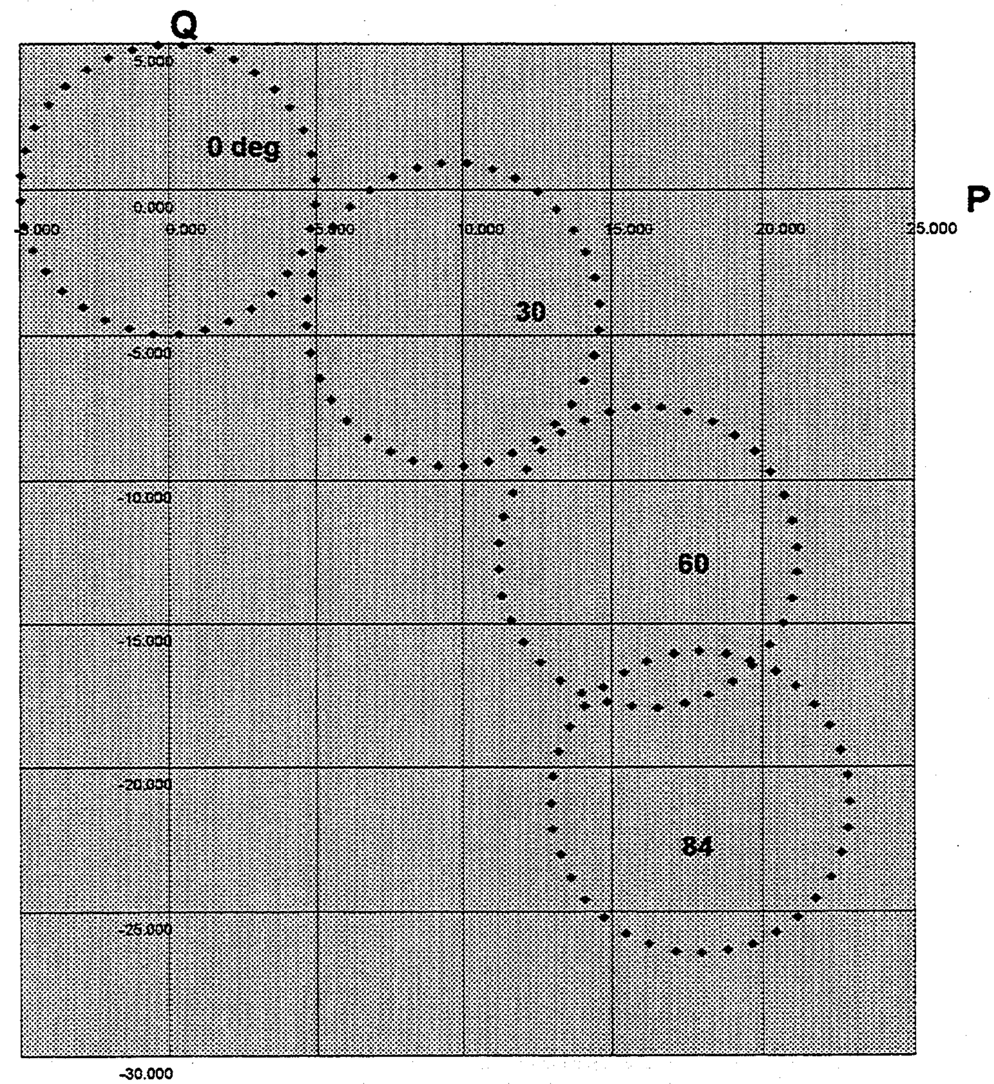


Figure 3.7 (a) - UPFC for Changing Load Angle $V_i = 0.25$, V_T Unconstrained

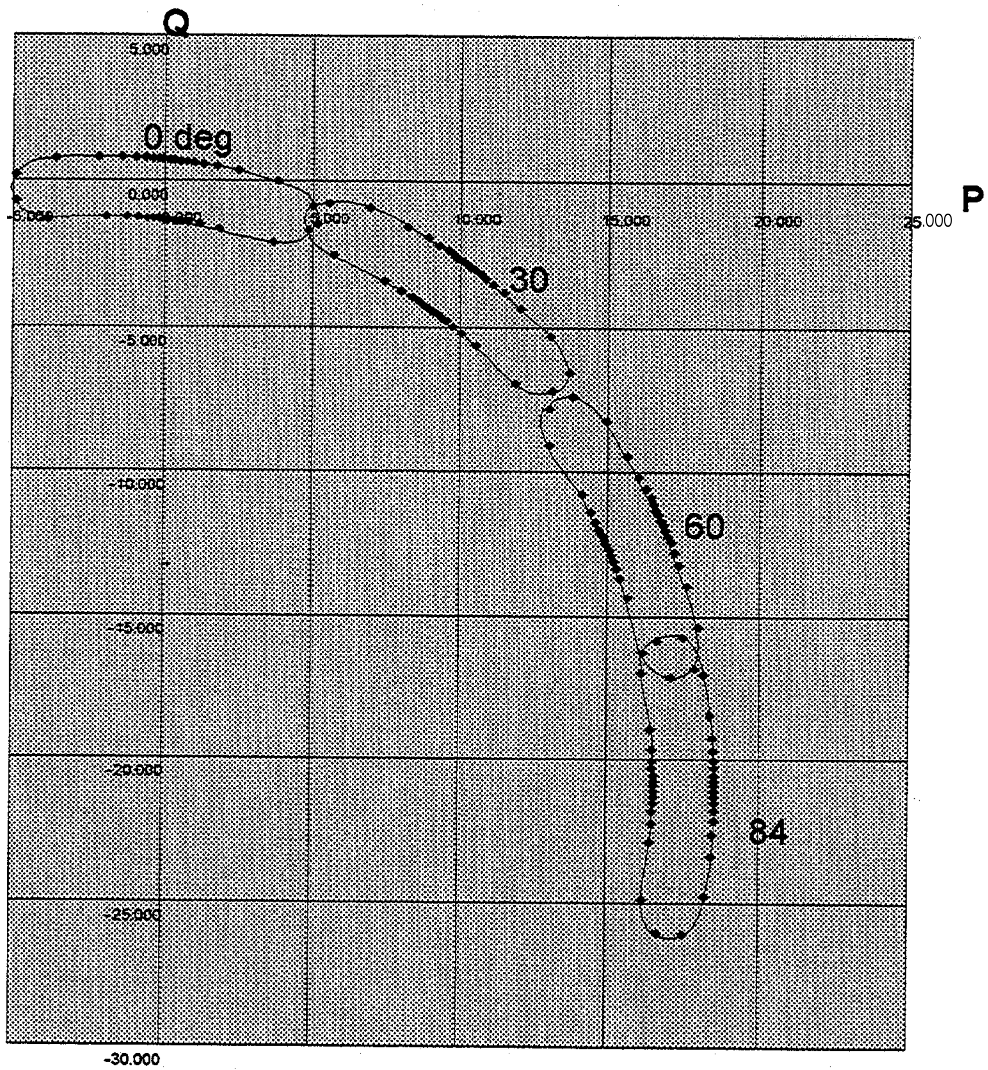
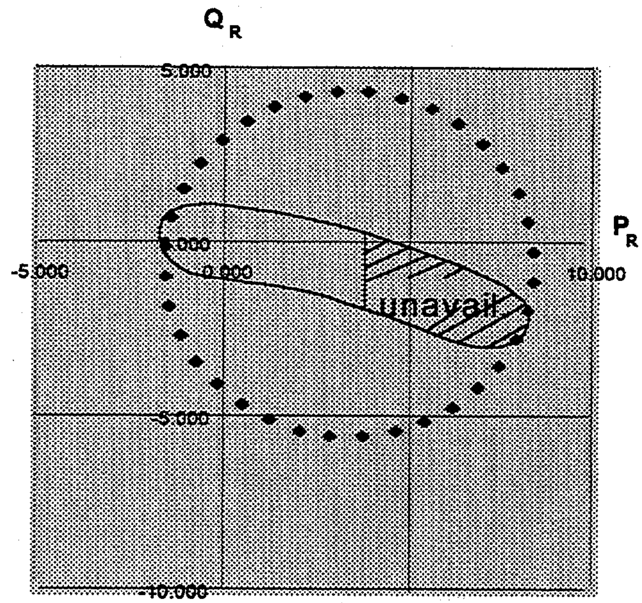
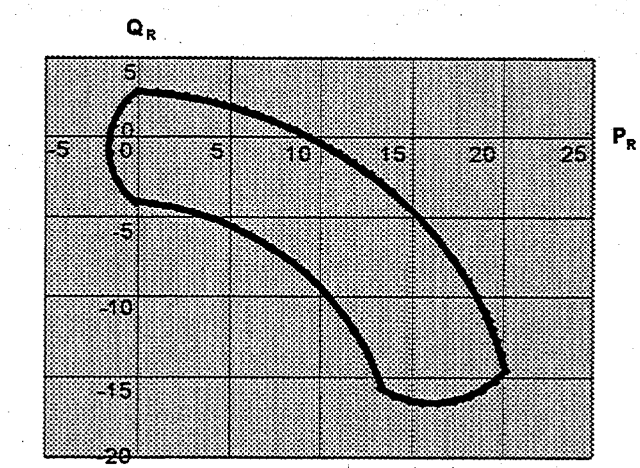


Figure 3.7 (b) - UPFC with Changing Load Angle; $\mathbf{V_i}$ Constrained to Maintain $0.95 \leq V_T \leq 1.05$



(a) - Steady State UPFC Characteristic with V_i & P_R constrained



(b) - Theoretical Dynamic Range; V_T between 0.8 and 1.15 p.u.
and 10 < 6 < 60 degrees

Figure 3.8 - Theoretical Steady State and Dynamic Power Control Ranges of UPFC

3.4.5 Static Synchronous Series Control (SSSC)

Removing the shunt STATCOM from the UPFC yields the SSSC. Without the ability to transfer active power, as in the UPFC, the SSSC can only produce a variable voltage V_i in quadrature with the line current. In some sense it behaves like a series capacitor plus a series reactor used alternatively. For some system conditions (initial power flow, line and system reactances, etc) the SSSC can actually reverse the power flow similar to a PAR, making it more flexible than thyristor controlled series capacitors and reactors.

The operating principle is similar to the UPFC in that it inserts a voltage V_i that adds to V_S to give V_T as shown in Figure 3.9 (b). The equation for V_i is: $V_i = j A I$, where I is the line current, itself a complex value and A is a real number limited in magnitude by the voltage rating of the SSSC.

A SSSC designed with the same maximum V_i rating of a given UPFC will operate along an arc that roughly bisects the operating regime of the equivalent rated UPFC as shown in Figure 3.10. The SSSC arc is a portion of a large circle, the parameters of which are dictated by ac system conditions alone [Ramey, 1996]. That circle in the P_R-vs-Q_R plane has a radius of $|SoZ^*/2R|$ with its center at the complex point described by $SoZ^*/2R$ where So is the Po + j Qo that flows without the SSSC and Z = R + j X , the line impedance. The arc of operation along that circle is derived from the equation:

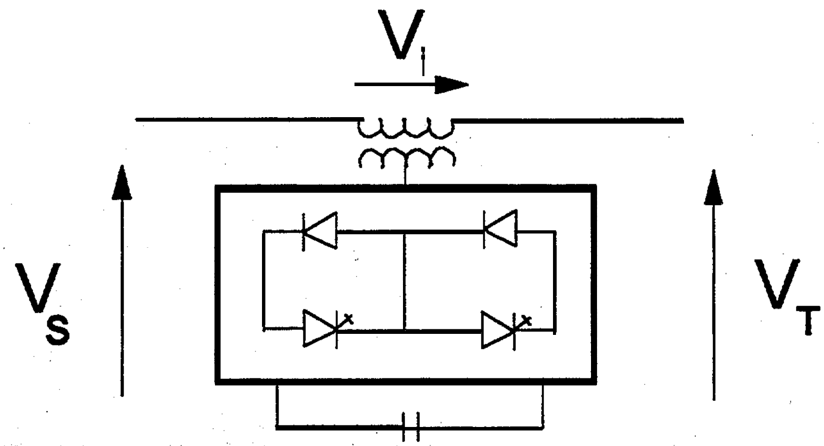
$$S_R = P_R + j\,Q_R = SoZ^*/[R+j(A-X)].$$

Assuming the same numerical example based upon the 50 mile 230 kV line, and a voltage rating (maximum $|V_i|$ value) of 0.25 p.u. as before, the SSSC operating characteristic is shown as a solid line in Figure 3.10. The dashed shape. drawn on the figure defines the operating region of the UPFC with same V_i rating. While the UPFC can operate anywhere inside the dashed region, the SSSC is restricted to operate on the solid line only. However, power control range is similar except the SSSC may not be able to reverse power, as is the case chosen.

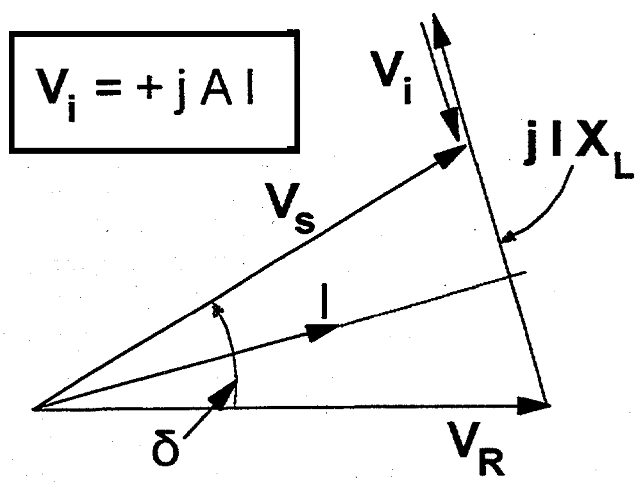
The SSSC's capability to control power flow by modulating V_i is dependent upon current flow. If the system dispatch conditions lead to near-zero power and load angle, the SSSC is incapable of significant control. This is similar to series (C and/or L) compensation. The UPFC and PAR (discussed next) are capable of changing the power flow even starting from zero flow conditions. Like the UPFC case, $|V_i|$ of the SSSC must be constrained to observe practical limits on $|V_T|$.

3.4.6 Power Angle Regulating (PAR) Transformer

Conventional mechanical PARs are commonly used for the control of steady-state power flow. If fast transient angle shifts are needed, some or all of the PAR's angle range can be switched with thyristor switches. This analysis assumes the buck-boost winding is oriented such that the series voltage V_i is derived from, and is in quadrature with the V_S phasor, as is



(a) - One-Line Diagram for SSSC



(b) - Phasor Diagram for SSSC

Figure 3.9 - One Line and Phasor Diagrams for SSSC

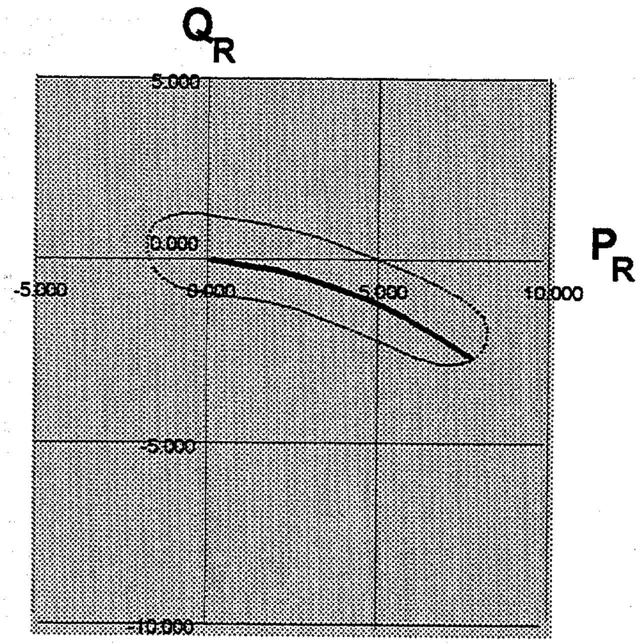


Figure 3.10 - SSSC Characteristic (Arc) Over UPFC (dashed shape)

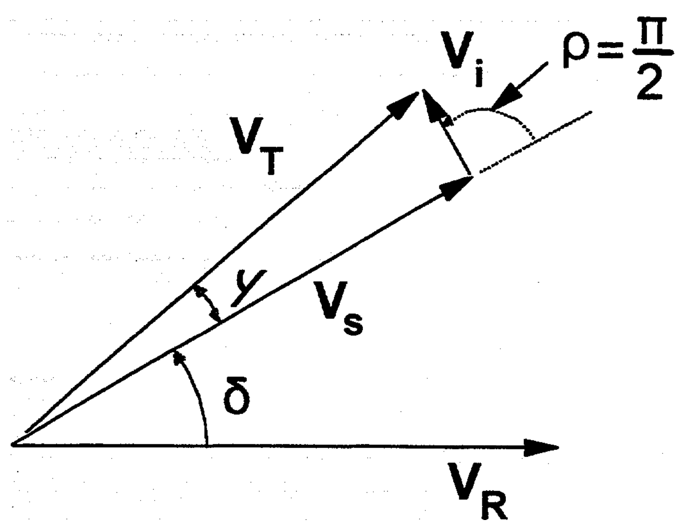


Figure 3.11 - Voltage Phasor Diagram for PAR Operation

common with mechanical PARs. That assumption is depicted in the phasor diagram in Figure 3.11. The resultant of $\mathbf{V_S}$ and $\mathbf{V_i}$ yields $\mathbf{V_T}$ which is shifted in phase from $\mathbf{V_S}$ by shift-angle y (gamma). The phasor voltage $\mathbf{V_T}$ must still be constrained in magnitude as in the prior cases. $\mathbf{V_i}$ may be positive or negative; that is, rho is 90 or 270 degrees.

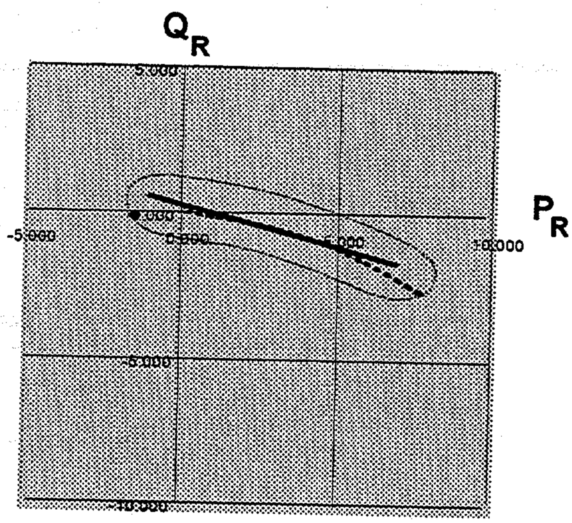
Consider the same 50 mile 230 kV line case as before. Imposing a limit of ± 0.25 p.u. on $\mathbf{V_i}$ is the same as applying an approximate limit of ± 14 degrees on the phase shift angle, gamma. For these compatible limits the maximum value of $\mathbf{V_T}$ is about 1.03 p.u. The reactance of the PAR transformer was modeled as variable from 0.5% to 1%, on 100 MVA base, over the 14 degree range in gamma.

The resulting variation in power $\mathbf{P_R}$ around the same 3.4 -j 0.64 point as before is shown in Figure 3.12 (a). That result is overlaid onto the results for the UPFC and SSSC from Figure 3.10. The PAR operating characteristic bisects the UPFC characteristic with a nearly straight line. Notice that it is able to reverse the power, whereas the SSSC was unable to do so with the given system conditions. The range of power control achievable with the PAR is slighty less than that of the UPFC. Had the PAR impedance been ignored, the range would have been the same as the UPFC as illustrated in Figure 3.12 (b).

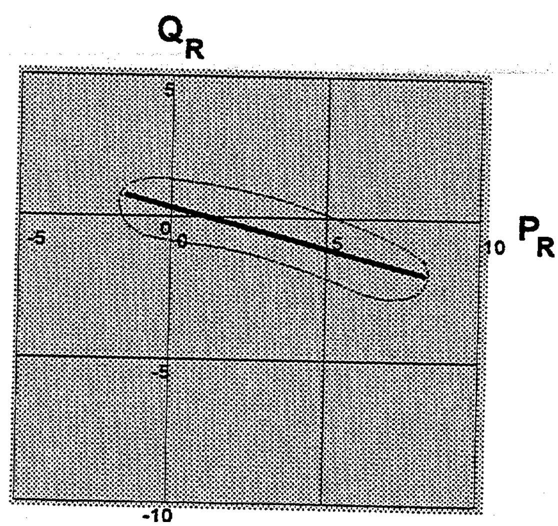
3.4.7 Series Capacitors

Series capacitors normally would not be considered for a 50 mile, 230 kV line. However, for completeness, the same example above was used to evaluate the use of series capacitor compensation varying from 30% to 50 % of the line's reactance. The plot in Figure 3.13 (b) shows the results. The operating trajectory lies along the SSSC curve, starting at So, the center of the UPFC range, and progresses about two thirds of the SSSC's boost range. Series capacitors cannot cause a decrease in power, so a reduction from the central point is not achieved However, adding variable series inductance as well as capacitors could provide bidirectional control capability. Although not common, reactor insertion is used occasionally as an emergency measure to avoid overloading on low voltage lines. For instance, such a scheme is used on a 115 kV line in Vermont which also has a PAR for normal slow control of the power transfer.

For this example, wherein the uncompensated power flow is already 85% of thermal rating of the line, insertion of even minimal capacitance loads the line to thermal capacity. This example does not exploit the beneficial effects that series capacitors display for long lines that are prone to stability limitations. However, for the same reason series capacitors have little leverage on power transfer in this case, they also do not cause $|\mathbf{V_T}|$ to exceed 1.05 either, a fact that does not hold for the 150 mile example discussed later.

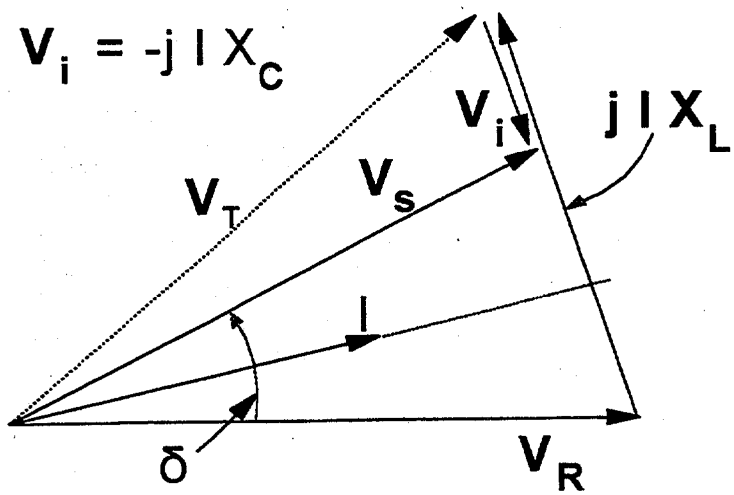


(a) . PAR Characteristic (solid line) over SSSC and UPFC (dashed)

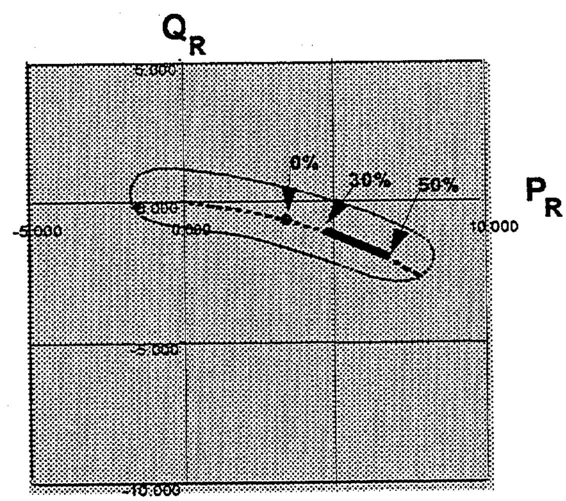


(b) - PAR-without X_t included

Figure 3.12 - PAR Compared with SSSC and **UPFC**



(a) - Phasor Diagram for Series Capacitors



(b) - Series capacitors (heavy overlay) compared to SSSC and UPFC

Figure 3.13 - Series Capacitors - Phasor Diagram and Power Control Range

3.4.8 Back-to-Back HVDC

Here again, it would be unusual to contemplate using a back-to-back dc (BTBDC) link interior to an ac network as depicted in Figure 3.3. They are typically used for interconnecting otherwise asynchronous ac networks. However, the BTBDC link can perform as "the ultimate **PAR"** since it can operate as a $\pm$ 180 degree PAR within the ac line's long term thermal limits.

As illustrated in Figure 3.14, the augmented load angle (delta plus gamma) between V_T and V_R can be varied over $\pm$ 180 degrees independent of what angle (delta) exists between V_S and V_R, the latter being dictated by the flows in the parallel ac system. Furthermore, if the BTBDC employs voltage source inverter technology similar to the UPFC, it can regulate the magnitude of V_T, unlike the PAR, while providing a pure phase shift (change in gamma). The PAR uses V_i in quadrature with V_S to achieve the change in gamma and large gammas cause unacceptable V_T magnitudes. That is why large angle shifts can only be achieved with several PARs in tandem.

If the BTBDC capability were illustrated on Figure 3.13 (b), it would appear as an extension of the UPFC's tubular shape between +400 MW (thermal capacity) to -400 MW, independent of initial operating angle in this case. The 150 mile example discussed next illustrates the superior control range of the BTBDC.

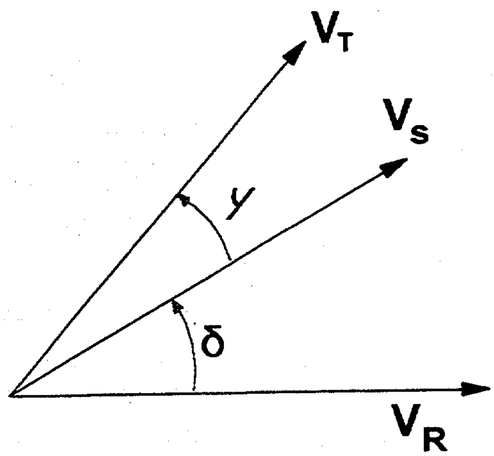
If an HVDC line were used in place of the ac line plus BTBDC, the operating characteristic in the P-vs-Q plane would be a circle of radius 400MVA, truncated (flattened) on top and bottom to limit the reactive power range. The vertical dimension (± Q range) would be dictated by the needs of the terminating ac systems.

3.4.9 Comparison of Power Controllability for 150 mile Example

This example is structurally identical to that in Figure 3.3 but the impedance is assumed to be $Z = 0.03 + j\,0.3$ p.u. on a base equal to the line's Surge Impedance Loading (SIL). Typical values of SIL and approximate thermal limits for a range of ac voltages are:

Voltage (kV)	SIL (MW)	Thermal (MW)
115	35	100
230	150	400
345	400	1200
500	900	2600

These parameters vary with line construction practices, but the above values are typical. Also, when expressed in per unit on the SIL base, a 100 mile section of line has a reactance approximately 0.2 p.u. A 150 mile line therefore has a reactance of 0.3 p.u. on its SIL base. An X/R ratio of 10 is assumed and charging effects were ignored, Parenthetically, the line charging has less than 5% impact on X for lines less than about 200 miles in length.



Where:

$$P = \frac{|V_T||V_R|}{|Z|}\sin(\delta + y - a) - \frac{|V_R|^2}{|Z|}\sin\alpha$$

instead of

$$P = \frac{|V_s||V_R|}{|Z|}\sin(\delta - a) - \frac{|V_R|^2}{|Z|}\sin\alpha$$

$$a = \arctan(R/X)$$

Figure 3.14 - Phasor Diagram for BTBDC Lii Acting as a PAR

The comparison of UPFC (two V_i Ratings shown), SSSC, PAR, TCSC and BTBDC' for the 150 mile, 230 kV example is summarized in Figure 3.15. That figure illustrates the relative performance of the competing approaches assuming a central (initial uncompensated) operating point of: So = 2.7-j 1.9 p.u. on SIL (e.g., SIL=150 MW and δ = 60 degrees.

Observing the results in Figure 3.15, one sees that the PAR and UPFC have about the same power control range, neither exceeding the thermal capacity of the line. The SSSC shows a slightly larger power control range for the chosen system conditions since the operating "arc" is on a larger diameter circle than the UPFC and PAR follow. Inclusion of device losses and other practical matters ignored herein could change these rankings.

Doubling the UPFC voltage rating (to 0.5 p.u.) nearly doubles its power control range. Although not shown, matching that doubled range with a PAR might require two PAR's in tandem to keep $|V_T|$ within 'its nominal range. The gamma range of a single PAR must be constrained to about ± 18 degrees ($V_i = \pm 0.32$) which increases the control range by 33% over the case shown in Figure 3.15. Also not shown applying a SSSC with $|V_i| = 0.5$ is unacceptable as it exceeds the maximum terminal voltage of 1.05 p.u. Limiting the SSSC to $V_i = \pm 0.32$ increases its operating range by about 28% over the $|V_i| = 0.25$ case without encountering problems with $|V_T|$.

The controlled series capacitors are quite effective in increasing the power transfer, but the full 0 - 50% compensation range selected cannot be fully exploited without exceeding the thermal rating of the line. The maximum compensation allowed in this case is 35%. Furthermore, using more than 10% of series capacitor compensation in one location would cause $|V_T|$ to exceed 1.05 p.u. Finally, as before, controlled series inductance (not shown) would be required to enable a power reduction from the uncompensated value of 2.7 p.u.

The back-to-back dc option shows the greatest ability for power control. Assuming V_T and V_R both at 1 p.u., the range is from -3.6 p.u. at -150 degrees to +3.3 p.u. at about +25 degrees. Pushing gamma beyond 25 degrees is ineffective since the total angle between V_T and V_R exceeds 85 degrees, the approximate peak of the P-vs-Q curve for this system. Of course, the controls must observe the ac line's thermal capacity, which would be about 3 p.u. SIL in this example. If the BTBDC regulates the magnitude of V_T, then the BTBDC characteristic will appear as a region bounded by two concentric partial circles from limit to limit. That is the same as extending the UPFC operating (tubular shaped) region along BTBDC centerline (sequence of squares) shown in Figure 3.15.

A UPFC with a series winding and inverter that is capable of full voltage ($V_i = \pm 1$ p.u.) would result in the control range shown in Figure 3.16. Even with both UPFC inverters rated at full voltage similar to a back-to-back HVDC link, the UPFC cannot reverse the power in the given example. That is because shift-angles (gamma) greater than 60 degrees cause the line-side voltage V_T to exceed 1.05 p.u. in magnitude. For identical converter voltage and MVA ratings, the back-to-back HVDC (or HVDC line) would provide superior range of control, compared to a UPFC, in this example.

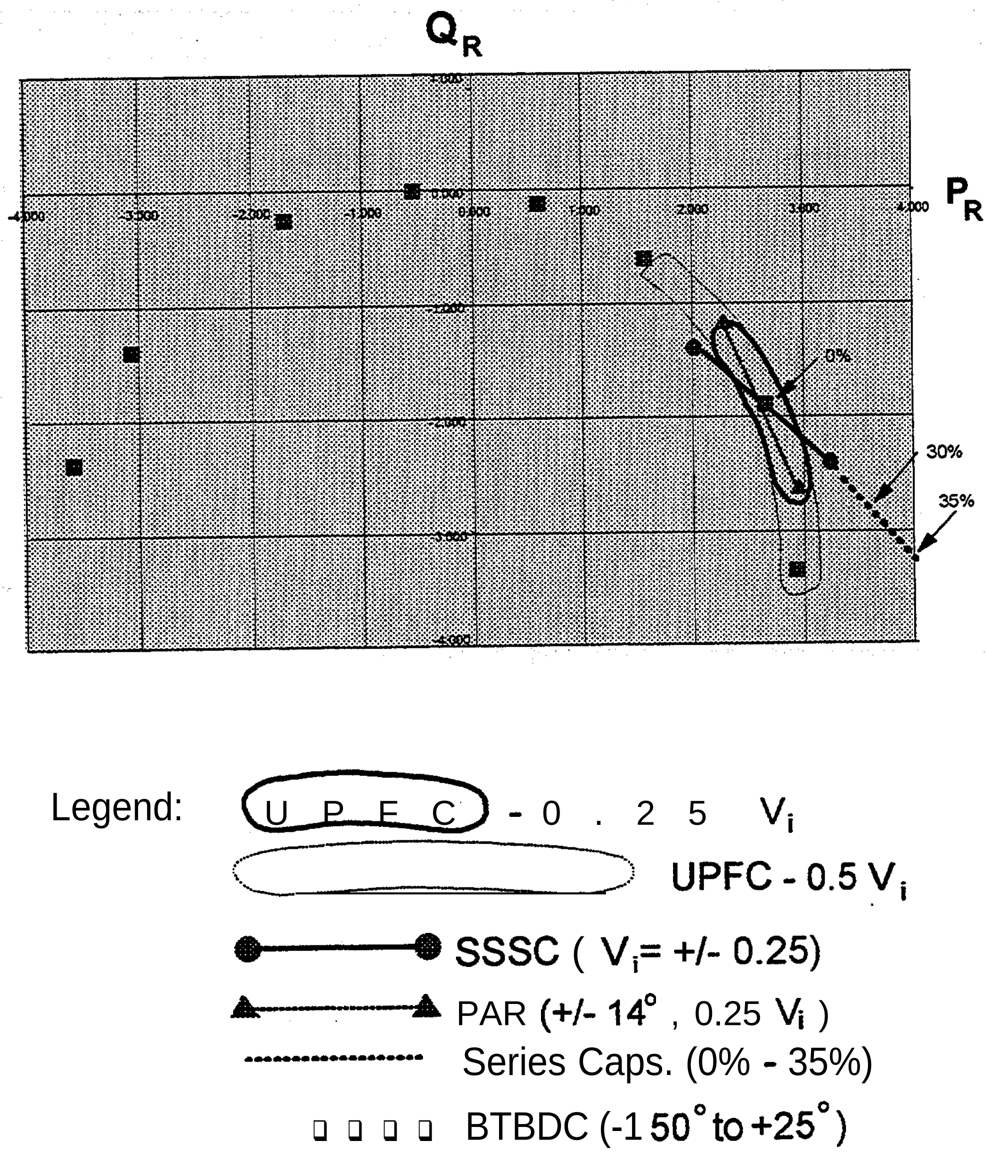


Figure 3.15 - Comparison for 150 mile Line Operating Around δ = 60 degrees
P & Q given in p.u. on SIL base

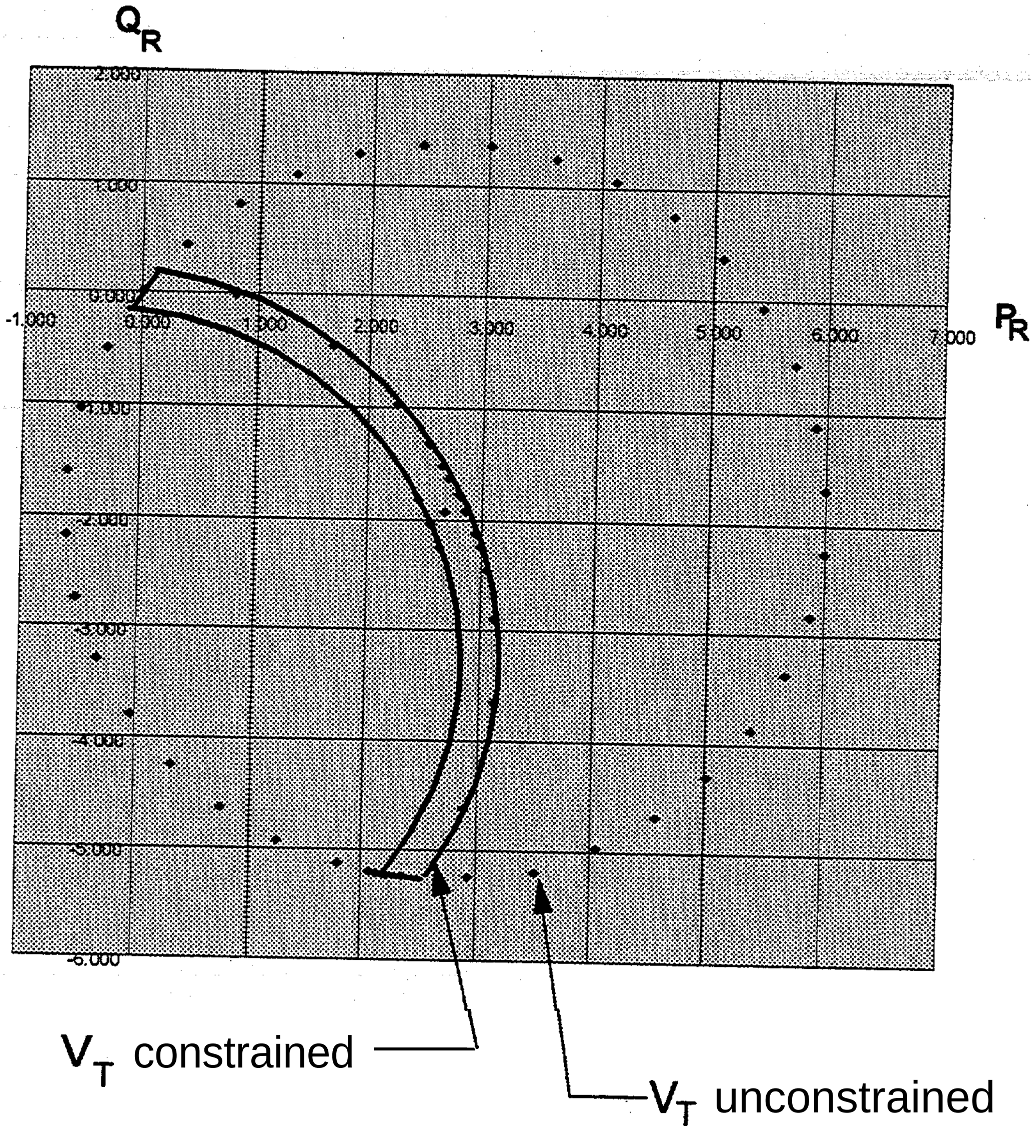


Figure 3.16 - Range of Power Control for UPFC with Maximum Inserted Voltage Vi =1 p.u. for 150 Mile Line Example, P & Q given in p.u. on SIL base.

3.5 SUMMARY

HVDC can play a significant role in meeting the functional needs of the nation's future transmission needs. Where interconnection of non-synchronous ac networks are involved, dc has a distinct advantage over ac. Indeed, there may be a case for splitting some of the existing ac networks with dc lines or back-to-back interconnections in strategic locations to permit energy exchanges. In those cases, and in all other situations where ac is a technically feasible, dc may compete favorably if the cost of converters is reduced. Section 6 contains economic comparisons between ac and HVDC for seven representative scenarios that are worthy of consideration in the future as we push our transmission systems closer to the limits of their capabilities.

4. TRANSMISSION COSTS

The total cost of a new transmission line is composed of a long list of cost elements some of which are common between ac or HVDC lines. In both cases there will be substation (terminal) construction costs and line construction costs. HVDC terminal costs are typically greater than ac line terminal (substation) costs but a long ac line generally will be built with intermediate switching substations that add a minor amount to total ac line cost. The cost of losses incurred over the life of the Iine can be substantial, so the present worth of the estimated annual cost of losses should be considered, especially where ac and dc are being compared. This section attempts to identify all the major cost elements and provides estimates, where possible, for future costs. Some of these costs are used in Section 6 to compare HVDC and several ac options in terms of the "break-even" distance.

4.1 COST ELEMENTS

The elements of cost for a new transmission project are listed below in rather broad categories. Selected categories are further subdivided later in this section.

- Capital cost of HVDC terminal equipment and / or ac substation equipment
- Terminals / substations construction cost
- Transmission line materials and construction cost
- Capital cost of spare parts and subsystems
- Cost of reinforcing ac system(s) to which new project assets interface
- Site real estate for ac / dc terminals and other substations
- Real estate for line right-of-way
- Access, roadways, and utilities
- Permits, environmental assessments and licenses
- Engineering, planning and development costs
- Financing
- Operating and maintenance (O&M) costs
- Power / energy Losses over the estimated life of project assets

Some of these cost categories will apply for transmission line upgrades as well as for new lines.

4.2 LINE ROW AND CONSTRUCTION COSTS

The cost per mile for ROW varies widely depending upon local land values. The width of ROW also will vary by locality as licensing rules vary. Construction costs will of course vary some due to local labor rates, but is dictated by the terrain to be covered, difficulty of access, the number of highway crossings, and a host of other reasons. The total all-inclusive costs include consulting and legal fees to assist in licensing and permitting activities. These total costs may vary from about $250,000 per mile in sparsely settled areas of the western U.S. to over $1,000,000 per mile for a new line in the developed northeastern area of the U.S.

The HVDC- vs.- ac break-even distance calculations in Section 6 assumed the following data as "typical" for the cost of land and construction only. Engineering, legal and all other indirect costs would add to the values shown below. While those indirect costs might double the cost of a given line, they were assumed to be equal for either ac or dc line for the comparison in Section 6.

Cost of land was assumed to be $4,000 per acre.
Assumed ROW widths and construction costs yielded:

Line Voltage and ac or dc	ROW width	acres/ mile	Cost/ mile $/mi	Const . $/mi	Total
2x230 kV ac	135 ft	16.4	$65K	$375K	$440K
345 kV ac	150 ft	18.2	$73K	$500K	$573K
500 kV ac	200 ft	24.2	$97K	$690K	$787K
3x ±188 kV dc	135 ft	16.4	$65K	$375K	$440K
lx ±281 kV dc	125 ft	15.1	$61K	$330K	$391K
1x ±408 kV dc	140 ft	17.0	$68K	$460K	$528K

Very often, existing ROW may be available so no new land is required. Such was the case for the Sandy Pond to Quebec HVDC Phase II project, where existing ROW was used for much of the HVDC line plus all of the new 345 kV and 115 kV line work done to support the project. However, the cost of reconstructing old tower lines on those ROWs can be more costly than simply building on a new empty ROW. Every project will be different, so the above data cannot be used in general.

The cost of line losses over the life of the assets should be considered in any comparative analysis, such as the break-even distance calculations in Section 6. Again, various assumptions could be made based on locally variable parameters. The comparison of dc and ac in Section 6 used the following assumptions.

-For an interest rate of 8% and a life of 30 years, the present-worth-factor of 11.26 resulted.
-Demand Charge = $900/KW
-Energy Charge = $30/MW-hr
-Loss Factor (average losses / losses at peak load) = 0.4

Using the assumed data listed above, the present worth of losses was computed to be about $2,000 per KW.

4.3 CONVENTIONAL AC SUBSTATION EQUIPMENT

The total cost of a substation includes the cost of circuit breakers, disconnects, transformers, and any special equipment such as reactors, capacitors and metering. The cost of land value (for new substations) and civil work must be included. The present worth of substation losses (transformers, etc.) should also be considered in any comparative analysis.

A previous study entitled "Comparison of Costs and Benefits for DC and AC Transmission" ORNL-6204, published in February 1987, cites typical installed costs for all of the typical equipment in an ac substation. Most of that data was extrapolated from the Electric Power Research Institute's 1982 *Technical Information Guide.* Rather than extrapolate each cost element again, the analysis in Section 6 assumed the overall cost of a new or reconstructed ac substation was $10/ KW for a new line entry. For instance, the substation costs associated with a single ac line rated for 1000 MW would be $10 million. This is about one tenth of the $100/KW for a conventional HVDC converter station, in today's estimated costs (see Section 4.4).

The losses in substation equipment were assumed to be 0.5% of the line capacity for ac and 1% of the converter rating in the HVDC case. The cost of losses over the assumed 30 year life of the substation assets was about $2,000/KW as cited in Section 4.2.

4.4 HVDC CONVERTER STATION TURNKEY COSTS

Utilities usually construct an HVDC transmission project by requiring the vendor to deliver the HVDC station(s) as a turnkey project. The cost of the HVDC station turnkey project is one of the major direct costs. The HVDC station major components include the converter valves and valve cooling, the converter transformers, the DC switchyard, the AC switchyard, the controls and protection, the civil works, the station auxiliary power, and the project administration and engineering.

Vendor Survey of 1995-96 HVDC Turnkey Costs. Three HVDC vendors were asked to complete a survey to estimate the turnkey cost and major component breakdown for four representative HVDC systems. The four representative systems and the estimate assumptions are shown in Tables 4.4.1 and 4.4.2.

Table.4.4. 1- Four representative systems.

System No.	DC Voltage	Capacity	AC Voltage
1	+/-250 kV	500 MW	230 kV
2	+/-350 kV	1000 MW	345 kV
3	+/-500 kV	3000 MW	500 kV
4	Back-to-Back	200 MW	230 kV

Table 4.4.2 - HVDC converter station estimate assumptions.

1. There will be two ac transmission tie lines.
2. There will be one electrode per converter station.
3. A short circuit ratio of 4.0.
4. Temperature range of -30 to 30 C (dry bulb).
5. Seismic Category - Zone 2.
6. Moderate soil conditions.
7. Building space for equipment and required indoor storage only.

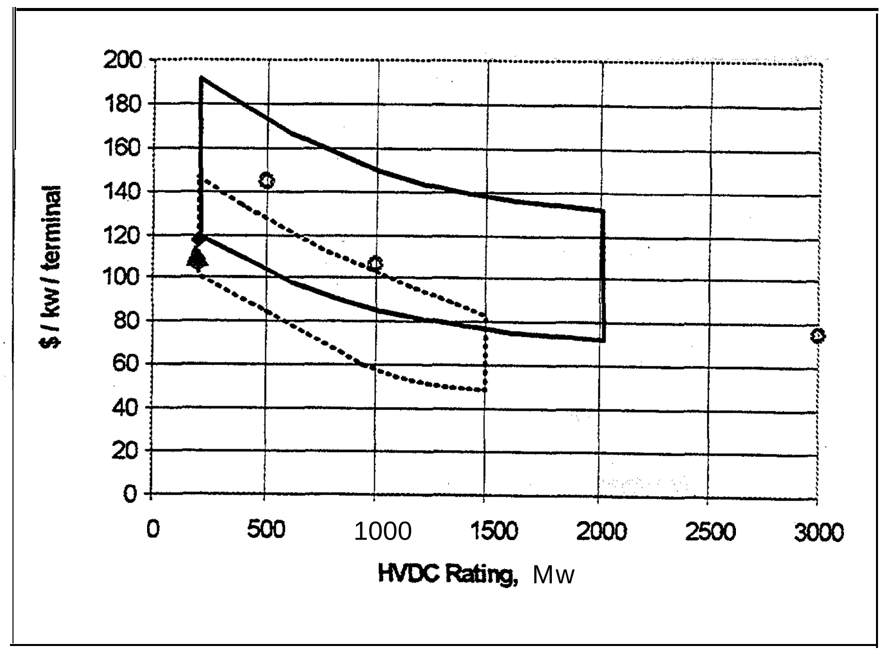
The vendors all replied to the survey and all noted that the estimates were based on the supply of two bipolar stations for the transmission systems. Table 4.4.3 provides a summary of the average of the major component cost breakdown and estimated turnkey cost for each of the four representative systems. .

The survey also asked the vendors to estimate the possible reductions due to post-year-2000 HVDC technologies. One vendor provided a breakdown of the estimated reductions of between 6.9 - 17.7%, one vendor estimated 30% over the next ten years, and one vendor did not provide any estimates. All of the vendors provided comments regarding the possibilities for reductions. They suggested that the largest savings would be realized if the converter transformer could be eliminated [Vithayathil, 1995]. Advancements in valve technology would also result in large savings. The use of outdoor valves could reduce the building costs, but may expand the switchyard. Advances in control, protection, and communications technology are feasible and cost effective. Finally, standardized designs could reduce project administration, engineering, manufacturing, and construction costs,

Table 4.4.3 - Average breakdown of HVDC turnkey costs from three HVDC vendors.

Item No.	Project Component	Back-Back 200 MW	+/-250 kV 500 MW	+/-350 kV 1000 MW	+/-500 kV 3000 MW
1	Converter Valves	19.0%	21.0%	21.3%	21.7%
2	Converter Transformers	22.7%	21.3%	21.7%	22.0%
3	DC Switchyard	3.0%	6.0%	6.0%	6.0%
4	AC Switchyard	10.7%	9.7%	9.7%	9.3%
5	Control, Protection, & Communication	8.7%	8.0%	8.0%	7.7%
6	Civil Works	13.0%	13.7%	13.7%	13.7%
7	Auxiliary Power	2.0%	2.3%	2.3%	2.3%
8	Project Administration	21.0%	18.0%	17.3%	17.3%
	Total Estimated Cost	$43.3 MUSD	$145 MUSD	$213.7 MUSD	$ 451.7 MUSD
	Cost - $/kW/Terminal	$108	$145	$107	$75

As seen in the above table and Figure 4.1, the cost per KW decreases with MW rating for transmission line cases. Figure 4.1 compares the above cost data with previously published cost estimates. The costs shown in Table 4.4.3 and Figure 4.1 for the back-to-back case is for the complete installation.



Legend ○ Converters for transmission lines -voltage from 250 kV to 500 kV (Table 4.4.3)

▲ Back-to-Back converter Won - monopole with low voltage (Table 4.4.3)

Range of costs (1992 dollars) shown in EPRI's HVDC Handbook

Range of costs suggested by Hingorani in April 1996 Spectrum Article

Figure 4.1 **-** Typical Variability of HVDC Converter Costs

4.5 HVDC TOTAL INSTALLED COSTS - NEW ENGLAND ELECTRIC'S PHASE I AND PHASE II SYSTEMS

The breakdown of the total project costs for the New England portion of the Phase I and II HVDC transmission systems is provided in Table 4.5.1. These breakdowns include the direct and indirect costs for each major component. The "all-in" Phase I project cost was approximately $200 per KW for one 690 MW, ±450 kV converter station, 58 miles of dc transmission line, an electrode and its 11.5 mile electrode line insulated for 34.5 kV, and various 230 kV ac reinforcements. The total Phase II project cost was approximately $240 per KW for one 2000 MW, ±450 kV converter station, 133 miles of dc transmission line, a 242 mile electrode line insulated for 75 kV - Sandy Pond shares an electrode located in Quebec with the Des Cantons and Nicolet terminals, and ac system reinforcements. The ac system reinforcement costs included about 90 miles of new single-circuit 345 kV transmission lines, about 35 miles of reinforced 115 kV, and a new -125/+425 MVAr SVC added in Maine to reinforce the 345 kV intertie to New Brunswick. A breakdown of the approximately $34 million cost for the SVC is given in Section 4.7.

The total installed costs in Table 4.5.1 are broken down into 12 "items". Each of those items consists of direct costs and indirect costs. The direct costs include construction material and labor cost associated with the physical asset. Indirect costs include licensing and permits, legal, finance, project administration, insurance, taxes, and interest. The indirect costs were 32% of the total costs for Phase I and 20% of total costs for the Phase II project. Alternatively, the indirect costs expressed as a percentage of the direct costs are 47% for Phase I and 25% for Phase II.

The direct costs are further divided into turnkey converter station costs and other developer's direct costs. The turnkey costs for the Phase I and Phase II converter stations were 38% of the direct costs for Phase I and 56% of direct costs for Phase II. The total vendor's turn key cost for both projects were less than $100/KW, about half of the total project costs. The remaining major components of an HVDC transmission project are the indirect costs; the utility's portion of the converter station civil works, the HVDC transmission line, the earth electrodes and line, the converter station -to- ac tie-lines, and other network reinforcements.

Table 4.5.1 - Breakdown of total installed cost for the Phase I and II HVDC projects.

Item No.	Description of Item	Phase I, (%)	Phase II, (%)
1.0	Converter Valves	11.1	9.08
2.0	Converter Transformers	9.6	8.72
3.0	dc Switchyard Equipment	5.7	3.26
4.0	ac Switchyard Equipment	12.1	11.67
5.0	Station Auxiliary Power	0.6	0.42
6.0	Control & Protections	5.0	2.06
7.0	HVDC Station Site Costs	6.6	11.96
8.0	HVDC Transmission Line	39.2	27.08
9.0	ac Transmission Tie Lines	0.5	0.27
10.0	dc Earth Electrode	2.4	0.00
11.0	dc Earth Electrode Trans. Line	0.5	0.62
12.0	ac Network Reinforcements	6.8	24.87
	Total % of Items	100	100

4.6 ESTIMATED COSTS FOR FACTS CONTROLLERS AND RELATED AC SYSTEM COMPONENTS

The estimates of costs for FACTS controllers were derived from various EPRI reports, except for the estimate for UPFC. The estimate for UPFC was obtained, from a vendor engaged in the development of STATCOM and UPFC. Functionally, the vendor's UPFC concept employs two STATCOMs for the series and shunt portions of the UPFC. The estimating price for a UPFC therefore is based upon estimated STATCOM costs and a simple formula implied by the table entries.

Costs for conventional SVCs, series capacitors, shunt capacitors and power angle regulating transformers (PARs) are included for completeness and comparison. Table 4.6.2 contains the complete results of a literature survey plus a telephone survey with various vendors and consultants involved in the development of FACTS technologies. The following summary Table 4.6. I is derived, with some engineering judgement, from those data in Table 4.6.2.

Table 4.6.1. Summary of FACTS cost estimates for use in this analysis.

Shunt Capacitors	$8 / kVAr*
Conventional series capacitors	$20 / kVAr *
Conventional PAR transformer	$20 / kVA
Static Var Compensator	$40 / kVAr controlled portions
TCSC	$40 / kVAr controlled portions
STATCOM	$50f kVAr
UPFC Series portion	$50 / kW through power
UPFC Shunt portion	$50 / kVAr controlled

* An approximate average of $ 15/kVAr was used for ac line options in analysis in Section 6.

Table 4.6.2 - Estimated costs of conventional and FACTS devices based on literature search and t&phone survey. Rough estimates assume capital installed costs are "within the fence".

Device	$/kVA	Variance	Comments	Source	Yr. Publ.
SVC	45		60 w/ site costs	Chester actual costs	1990
	45			EPRI TR-103167	1993
	40	+50%,-30%		EPRI Scoping EL-6943	1990
	80		Seems high	EPRI TR-103641	1993
	35-50		low end = sw Cap/Reactor	ABB - Sales estimate	1995
STATCOM	48		Ignores OL duty Distribution class	GE/TVA Paper "Loss of Infeed.."	1996
	50		=high end SVC	W - Sales estimate	1995
TCSC	40	+50%,-30%		EPRI EL-6943	1990
	32.5			EPRI EL-6943 Vol. 2	1991
	40			EPRI TR-103641	1993
	40			EPRI TR-103167	1993
Shunt Caps	8			most references	
	10			EPRI EL-6943	1990
Conventional Series Caps	20	+50%,-50%		EPRI EL-6943	1990
	10			EPRI EL-6943 Vol. 2	1991
	13			EPRI TR-103641	1993
	20			EPRI TR-103167	1993
PAR (mech)	20	+15%,-15%		EPRI EL-6943	1990
	10-20			EPRI TR-103904	1994
TCPAR	50-100		Config. sensitive	EPRI TR-103904	1994
UPFC	50		for series portion	W - Sales estimate	1995
	50		for shunt portion		

Each of the FACTS Controller equipments consume losses at its characteristic rate. The average losses over a year of the equipment's life will vary depending upon how it is operated. For instance, static var compensators and other Thyristor-based equipment, typically consume losses equal to approximately 1% of the rating of the thyristor-controlled-equipment. That is, an SVC consisting of 100 MVAR of thy&or-switched capacitors will consume about 1,000 KW when all capacitors are switched on. If, on average, only 30% of the capacitors are on, the losses will be 30% of the device rating, or 300 KW.

FACTS controllers involving gate-turn-off devices are estimated to consume about 2% of the GTO-controlled reactive equipment rating. That is, a 100 MVAR STATCOM would consume about 2,000 KW at rated operation. The cost of losses for a FACTS - enahanced ac transmission line will vary depending upon the manner in which the power electronic switches are deployed and the average flow (MW or WAR) in them over the year. If the FACTS controller conducts substantial current most of its life, the present worth of losses consumed over a 30 year period could exceed the initial capital cost of the equipment.

4.7 ACTUAL COSTS FOR CHESTER STATIC VAR COMPENSATOR

A -125 / +425 MVAr SVC was installed on *a 345* kV transmission line as part of the ac reinforcements for the New England Phase II HVDC project. The indirect costs for this project were 14% of the direct costs. The turnkey SVC vendor costs were 86% of the direct costs for this project. Table 4.7.1 provides a breakdown of the total installed cost for the major components of the SVC project.

The $-per-kVAr costs provided in Table 4.6.2 above was done by dividing the appropriate cost elements by 550,000 kVAr which is the sum of all thyristor controlled reactive power. For a total "within-the-fence" cost, take items 1 through 6, which yields $60/kVAr. This is quite high since a new 345 kV substation was needed. For only the'purchased SVC equipment within the fence, take items 1 through 5, which gives $45/kVAr.

Table 4.7.1 Breakdown of total installed cost for the -125/+425 MVAr SVC at Chester, Maine.

Item	Description of Item	Percent of Total Project
1	Thyristor Valves	16.39
2	345/24 kV Transformers	19.82
3	ac Switchyard Equipment	22.48
4	Station Auxiliary Power	5.47
5	Control & Protections	8.47
6	Station Site Costs	23.04
7	ac Transmission Tap Line	2.88
8	ac Network Reinforcements	1.45
	Total %	100.00

4.8 SUMMARY

This section has assembled cost estimates from various published sources. This data is useful in making first-level comparisons between HVDC and ac alternatives. Because HVDC converter costs are central to this study, the purchasers cost of today's traditional HVDC converters was up-dated by the three major suppliers of such systems. That data is used in the economic comparisons provided in Section 6. While The indirect costs incurred by a developer/owner of an HVDC system will vary on each project so they were not included in the studies in Section 6. However, for completeness and as information to future developers of such systems, the full cost of developing the U.S. end of the Quebec - New England 2000 MW HVDC system and the Chester Static Var Compensator are presented as an examples. Estimated costs for FACTS controllers are also presented. Except for the Static Var Compensators, those devices or systems are still under development so their costs are very tentative. The analysis in Section 6 assumes the application of conventional compensation as for the ac alternatives studied, and uses the FACTS cost data in sensitivity assessments only.

5. OPTIMUM USE OF LIMITED CORRIDORS

Due to increased difficulty in obtaining new land for transmission lines, existing ROWs will need to be upgraded in some way to increase their capacity. The ways discussed in the past include: increased operating voltage, squeeze compact multiple circuit arrangements onto the ROW, replace three phase circuits with high phase order lines, overbuild with dc, replace ac with dc, and addition of underground ac or dc cable lines. Some presently unused corridors such as railroad passageways and highway medians might be exploited with the right technologies.

Conversion of ac to dc and overbuilding ac with dc are discussed in this section. Section 7 addresses the prospects of ac and dc cable. High phase order ac lines and other innovative ways of compressing multiple ac circuits in a tight ROW are not discussed further in this report. It might be sufficient to note that the compact transmission schemes adopted in Japan and other space-limited nations of the world should be reviewed for possible use in the U.S. The transmission ROWs in and around Tokyo are some of the most compact arrangements the author has seen. Six-circuit tower arrangements on very tall structures pass directly over buildings in some instances. Such a scheme might not satisfy U.S. National Electric Safety Codes (NESC) and require clever circuit arrangements to minimze the electromagnetic fields in occupied structures nearby. Eventually, a cost-effective way of burying our transmission must be found. In some places that need has been evident for years; for instance, all distribution and low voltage transmission is buried in The Netherlands where space is a premium.

5.1 CONVERTING AC TO DC

One way of increasing the capacity of a line by two or more times is to convert it to dc operation. The most straight-forward means would be to select a dc operating voltage equal to the maximum crest ac voltage of the original ac line, with due consideration for surge overvoltages. Applying the NESC guidelines for conductor-to-tower minimum clearances, the following eqaution can be derived.

$$V_{DC} = \sqrt{\frac{2}{3}}\, V_{AC} \frac{K_1}{K_2}$$

where: V_{DC} = dc pole to ground voltage
V_{AC} = rated ac line-to-line voltage (rms)
K_1 = ac switching surge factor in per unit, typically 2.2
K_2 = dc switching surge factor in per unit, conservatively 1.7

The above formula yields a dc voltage about 5% higher than rated Vac line-to-line. To be more conservative, one could ignore the switching surge factors where-upon the selected dc voltage is about 82% of the rated line-to-line ac voltage. The latter approach was used in Section 6 when comparing ac and dc.

For a new dc transmission line, voltage is usually determined by environmental performance (audible noise, radio interference, ion density and ion current). However, for an existing line the voltage would probably be determined by the insulators. The original ac insulators generally will not be compatible with dc operation, so they must be replaced. DC requires a larger leakage distance than does ac voltage. In addition, regular ac insulators cannot be used with dc voltage; insulator pin corrosion will increase the risk of insulators failing. DC insulators with sacrificial elements need to be used. It is estimated to cost two million dollars to replace the insulators on 100 miles of line.

The feasibility of HVDC conversion will of course depend upon the details of a particular application. A sample analysis given in Section 5.3.2 illustrates for a typical application some factors which must be considered. The same conductors may be used unless the estimated cost of losses over the remaining life of the line warrants a change out. The capacity of the line will be dictated by thermal considerations, rather than any stability-based constraint under which the ac line may have been subjected. The economics of converting a double-circuit 230 kV line into 3 bipoles of dc is studied in Section 6.

Technical considerations for converting a 230 kV double-circuit into 3 bipoles rated ±188kV dc is discussed in the next section. A special case for converting an ac line to dc to improve reliability to a radially-fed load area is considered in Section 5.3.

5.2 EXAMPLE: TECHNICAL ISSUES FOR CONVERTING DOUBLE-CIRCUIT 230 kV TO 188 kV DC

5.2.1 Insulators

As noted above, the primary issue in converting an ac line from ac to dc operation is the insulation. A typical 230 kV ac line may have 12 or 13 insulators per string. The example line may have room for 13 or even 14 insulators per string.

Insulators typically have lower flashover strength for dc than for ac under contaminated conditions. However, several means are available for improving contamination performance: fog type insulators, dc insulators, toughened glass insulators, and polymer insulators. Semiconducting glaze is reputed to be effective in improving contamination performance of dc insulators. Test data are sometimes contradictory, and not all manufacturers' insulators of the same general type perform equally well. Estimation of contamination is essential to the design in any particular location.

It appears [Pargamin, 1984; Kawamura, 1984] that use of fog or dc insulators in the same string length would provide adequate performance under light contamination conditions for 188 kV (nominally 190 kV) dc. It does seem that the insulators will need to be changed. In a real application study some lab tests using the insulators on the existing line would be appropriate. Some of the insulators can be removed and be tested in the lab for their dc performance. During the lab tests it must be recognized that the deposition of contaminant on dc insulators is much different from that on ac lines. At least the equivalent salt deposit density can be measured to give a starting place for testing the proposed dc insulators.

Clerici, et al [Clerici, 199 1] mention dc insulators with a leakage path/spacing ratio of 3 . 18. For light pollution they consider 28 mm/kV; for heavy pollution they consider 47 mm/kV. The ratio of 3.18 corresponds to 18.3 inches leakage for 5.75 inch units. The Lapp catalog, by comparison lists standard 5 3/4 x 10 bells at 11 or 12 inches leakage per unit depending on the mechanical strength and 17 inches leakage per bell for fog-type units.

Thirteen standard insulators per string at 230 kV corresponds to 1.03 inch/kV at 5% overvoltage. In the same length, assuming Clerici's ratio, dc insulators could have 238 inches leakage or 1.25 inch/kV at 190 kV dc. This is 3 1.8 mm/kV, more then Clerici cites for light pollution. This gives further encouragement to fitting enough insulation in the 230 kV structure for 190 kV dc.

Reference is made to a document [NGK, 1981] released by NGK, another manufacturer of insulators for dc operation. At 5.75 inches per unit, 14 insulators corresponds to a string length of 80.5 inches. NGK manufactures 25 kip dc fog insulators with the same length, 5.75 inches per insulator unit. Fog withstand voltage is given in kV/unit in Table 5.2.1 below.

Table 5.2.1 Fog Withstand Voltage for Subject NGK Insulators

Contamination Area	Clean	Light	Medium
Design ESDD, mg/cm^2	0.02	0.045	0.12
Fog Withstand Voltage, kV/unit	18.1	13.6	10.0
Fog Withstand Voltage, kV for 14 units	253.4	190.4	140.0
Design Withstand Voltage, kV/unit	16.4	12.4	9.1

The fog withstand voltage for 14 units is added to the table. From this table, 14 of these units are certainly adequate in a clean environment, and 14 units are just adequate in the specified light contamination condition. The NGK data reinforces the contention that the 230 kV double circuit structure could operate at 190 kV dc with replacement of the insulators.

Lastly, the Sylmar-Oregon HVDC line, as originally constructed, operated at ± 375 kV with 24- 5 7/8 x 11 ½ inch units. A simple ratio to 190 kV gives 12 units. This provides an additional sanity check. One can conclude that the conversion from 230 kV ac to ±188 kV dc should work, but some insulator testing and / or tight insulator specifications would be necessary.

5.2.2 Possible Use of Shield Wires for Neutral Conductor

This section explores the possibility of using the shield wires as a neutral to use one of the 3 bipolar dc lines for temporary monopolar operation. Exact details of a line modification depend on the exact line location and associated local meteorological factors. This discussion is intended to establish the general feasibility of the use of shield wires as a neutral for temporary monopolar operation of a single dc circuit on the converted structures. A detailed analysis must be performed for a specific installation to choose the proper replacement shield wire and insulation.

The sample line chosen for this analysis was constructed with 1 - 795 kcmil Mallard conductor per phase and 2 - ½ inch extra high strength steel shield wires.

Choice of Replacement Shield Wire

Assume the following weather conditions:

Air temperature 40 degrees C
Wind speed 2 feet/second
Angle between wind and conductor 90 degrees
Conductor at sea level, east/west direction, 43.0 degrees latitude
Sun time 12 hours
Atmosphere clear
Maximum conductor temperature 80 degrees C

Under these conditions Mallard conductor has a steady state thermal rating of 789.7 amperes.

Assume both ½ inch EHS shield wires are replaced with 336 kcmil Linnet ACSR conductor. Under the same weather and conductor temperature conditions, the steady state thermal rating of Linnet is 457.8 amperes, or 915.6 amperes for two conductors. Two Linnet conductors have more current handling capacity than a single Mallard and could function as a temporary neutral for monopolar operation of one of the dc bipoles.

It is necessary to consider whether the structures could handle the replacement shield wires. Table 52.2 gives a comparison of mechanical parameters of existing and proposed shield wires:

Table 5.2.2 Mechanical Parameters of Shield Wires

SHIELD CONDUCTOR	DIAMETER	WEIGHT PER THOUSAND FEET
½ EHS	0.495 INCH	517 POUNDS
336 KCMIL LINNET ACSR	0.72 INCH	463 POUNDS

Linnet ACSR has a lower weight and a greater diameter than the existing steel shield wire. Areas of concern include:

Wind and ice loading
Sag/tension behavior under heavy loading

The 336 kcmil ACSR conductor was chosen because it has traditionally been a commonly used size. Linnet was chosen of the available 336 kcmil conductors because it has the highest steel content and thus is the strongest conductor. The existing structures may be able to handle the loading of Liiet shield wires with no or little modification.

If wind loading is a problem for the structures several options are possible:

Use a smaller conductor (300 kcmil possibly)
Use a weaker 336 kcmil conductor
Use trapezoidal strand conductor

All three options would reduce the structure wind loading. If ice loading is a problem, trapezoidal wire or a smaller size ACSR are possibilities.

If sag/tension is a problem using higher than normal stringing tensions is possible, possibly requiring vibration dampers or T2 conductor.

Neutral Conductor Insulation Requirements

The existing shield wires are grounded at each structure for lightning protection. They would have to be insulated for use as a dc neutral. Insulated shield wires have been installed on ac lines for loss reduction or for power line carrier communication channels, so this does have precedent.

Depending on span length and mechanical loading, the shield wires are supported on post insulators, or hung from attachment brackets by suspension insulators. Suspension insulators are stronger and allow greater span lengths, but require modifications to the steel work to support them.

The insulators must be paralleled with spark gaps to allow the shield wire to be grounded to the tower in the event of a lightning strike. There is a problem with lightning puncture of the shield wire insulators on existing installations. A lightning stroke with a sufficiently fast rise time can puncture an insulator before external flashover takes place. Some means will need to be provided for detection and identification of failed insulators for replacement.

Concern must also be given to lightning protection at the converter station if insulated shield wire is used. One alternative is to move the neutral wire to a lower point on the structure and reinforce the structures for the first few spans immediately adjacent to 'the converter station. The existing ground wires will then serve their function as protection for the line and station. The extent of the precautions will depend on the lightning activity in the immediate location of the modified line.

5.3 CONVERTING SINGLE-CIRCUIT RADIAL, AC LINE TO DC FOR'INCREASED RELIABILITY

This report discusses possible methods to increase the reliability of radial lines without major line modifications and without construction of new lines to eliminate the radial configuration. Since'radial configurations are most likely to be at voltage levels below 230 kV typical physical and electrical line characteristics for 115 kV construction are chosen for the examples. The impact on reliability of sustained line outages (outage with lengths of hours or more) is the main subject addressed. Increasing power transfer capability during normal operation, a second but related consideration is also explored.

5.3.1 AC Alternatives

Several methods for improving the reliability of radial lines are listed below along with a short discussion of their feasibility:

1. Upgrade line quality

   To the extent that sustained outages on a line are due to failure of components, principally insulators, due to their poor condition (e.g. age), a change-out of insulators would be an attractive option for reliabii upgrading. Selective replacement of insulators based on measurements with sniffers looking for broken bells could be effective. Discussions with maintenance personnel may suggest that component replacement will have a significant bearing on sustained outage rates. In most cases, however, the effect on the sustained outage rate will be small.

   To the extent that sustained outages are initiated by flashovers due to lightning, one could consider either the use of lightning arresters, improvements in shielding (adding a second shield wire if only one is present), or in footing resistance as means to improve reliability. The theory would be that fewer flashovers would result in fewer component failures and therefore fewer sustained outages.

2. Add a spare conductor

It may be possible to add a fourth conductor to lines which use H-frame structures. However, there would be a considerable amount of line modification necessary, and all the construction probably would have to be done live-line. It is more difficult to add a fourth conductor to single pole steel structures. Because of the live-line construction requirement and the applicability only to the H-frame structure, the spare conductor is a possible, but not totally satisfactory option.

3. Insulate the shield wire and use as spare conductor

Instead of adding a spare phase, the shield wire could be insulated and used as a replacement phase. The insulation would also have to be done live-line, and would be easier on a H-frame structure than on a single pole support. Because of the shield wires rather high electrical resistance, the line could supply only about 50% of the peak load with one regular phase out-of-service. Even at 50% of load, there would be some voltage imbalance. Therefore, this option does not appear particularly attractive.

4. Operate two phases during faulted conditions

The transformers on a radial system could be converted to YY configuration, and when one phase was lost, the other phases could stay in service. However, this option does not appear attractive, because a rather complicated system would be needed for shedding three phase loads, because a large number of transformers may need to be replaced and because some voltage imbalances occur because of the high impedance of the 115 kV lines.

5. Operate two phase during faulted conditions and reconstruct third phase

Two phase operation could be done as discussed above, with a Y configuration transformer interposed. The winding in the transformer would reconstruct the three phases. However, the three phase reconstruction would supply only about 25% of the peak load, and even then there would be considerable voltage imbalance. Therefore, this option does not appear attractive.

6. Operate system resonant grounded [Gross, 195 1]

Transformers with a YY winding configuration could be interposed in the radial system and a reactance equal to 1/3 of the line zero sequence capacitive reactance inserted in the transformer neutral. Historically, this reactance has been called a Petersen coil, and many systems in the U.S. operated this way from about 1930 to 1960. The neutral coil drastically reduces the fault current, and a transmission line can simply continue operating with a phase to ground fault. The extra transformers in the system would add impedance which reduces normal power transfer capability, but it should be possible to counteract the impedance addition by operating the transmission line at a higher voltage during normal conditions, thus reducing the line impedance (in per unit).

There may be safety concerns when a system is kept in operation with a phase conductor lying on the ground. Since the conductor is on the ground, it should be at or near ground potential, which would help to minimize risk. To be certain the downed conductor potential is low, it could be solidly grounded at each substation. It is not certain if the National Electrical Safety Code (NESC) would allow operation with a phase-to-ground fault.

Irrespective of any efforts to improve reliability by novel methods of line operation, it may be necessary to extend the load capability of heavily loaded radial lines, e.g. by combinations of series and shunt compensation. Absent such moves, load growth alone could reduce the reliability of these radial lines.

5.3.2 Conversion To DC

Conversion to dc would substantially improve line reliability, since a bipole line would have double circuit reliability. If one pole was out-of-service, monopole operation would still be possible using the spare third phase as a return path for the current. In some cases it will be possible to service the entire load through the remaining monopole. If the entire load cannot be served with one pole then for a fault on one conductor the spare conductor might be reconnected using special switching to replace the faulted second pole.

The converter stations at the sending and receiving end impose two additional series elements in the system, so the reliability of the converter stations need to be considered when the overall reliability of the radial system is calculated for the dc option.

As noted in Section 5.1, the operating dc voltage will depend primarily on the insulators' performance. The original ac insulators generally will not suffice with dc and must be replaced. The sample analysis below illustrates, by example, some factors which must be considered.

Assume that at present there are 8 standard 146 mm insulators on the 115 kV line, then there is 1.17 m of gap. An example-dc insulator is 171.5 mm long per unit, with a leakage distance of 546 mm per unit. Therefore, it should be possible to fit 7 of these dc insulators in place of the existing standard string. The total leakage distance would then be 7 * 546 = 3822 mm. For an area with low contamination, 29 mm/kV is a conservative dc leakage distance. The maximum dc voltage is then about $\mathbf{V_{DC} = 3822 / 29 \approx 130\ kV}$

A voltage of ± 100 kV would be a conservative choice. Assume that Coot 795 kcmil ASCR conductors are being used. The ampacity of Coot 795 kcmil calculated, assuming an ambient temperature of 35” C, solar heating, 2 ft/s wind and 95° C conductor temperature is 964A Therefore, the dc transmission capability with ± 100 kV voltage would be 193 MW for the Coot conductor. The stability limit for a 115 kV ac line will depend upon its length and may be much lower. The stabiity limit for a 50 mile uncompensated 115 kV ac line is approximately 100 Mw.

With one dc pole out-of-service half the transmission capacity (96.4 MW) would still be available. The ampacity calculated above is for summer conditions; during other times of the year the ampacity would be greater. In addition, during emergency operation it might be possible to run the conductor above 95” C. As a result, it may be possible to serve the entire load even with one pole out using the spare conductor as a return path for the current. If a ground return is possible it may be possible to serve the load even with two conductors faulted. When a dc radial link feeds a non-motor load, forced commutation may be needed [Tumali, 1984].

5.3.3 Outage Statistics

For normal ac circuits all three phases are open for a fault on any phase. Every fault thus results in complete power interruption. The impact of having a fault on one conductor, two conductors, or three conductors will be different for the ac and dc alternatives discussed in Section II and III. As explained in the previous section for a dc line the amount of power interrupted with one or two conductors faulted will depend upon whether the spare conductor can be used to replace the faulted phase or only to provide a metallic return path and also depend upon whether a ground return is available.

The impact on power system reliability of any measure which increases power transfer with faulted conductors will depend on the frequency and duration of one conductors, two conductor or three conductor faults. It is therefore useful to review surveys of outage data. We must review 115 kV ac outage data since there is no actual experience where dc is transmitted on lines built for ac. We assume that for a given tower design and conductor configuration the probabilities of having a fault on one conductor, two conductors or three conductors do not depend significantly upon whether the line is operated with ac or dc. In reviewing that data, the most relevant questions are:

a) What percentage of <u>sustained faults</u> involve 1 conductor? 2 conductors? 3 conductors?
b) What is the expected frequency of sustained faults in each category?
c) What is the same data as in a) and b)., but for terminal substation equipment failures?
d) Wbat percentage of the single conductor sustained faults are on outer phases?

There are very few industry statistics which respond to these questions and those which do exist must be interpreted <u>very</u> carefully. Reports often mix single and double circuit construction, variety of shielding and footing resistance conditions, a variety of surge protective practices, and in no case do they take into account the age of a line. The latter can be important since a line in poor condition can expect a greater percentage of flashovers to results in sustained faults than a line in good condition. However the error validity in the ratio of various phase involvement's is doubtless much greater than the validity of frequency of occurrence predictions. Thus the improvement ratio is apt to be reasonable accurate.

Table 5.3.1 shows the results of reviewing three groups of data [CEA,1988; AIEE,1952;Adler,1993]. That data is reviewed for 115 kV lines except as noted as it pertains to each of the above questions

Table 53.1. Outage Statistics From Three Surveys

Source of Outage Data	Percent of Faults which involve 1, 2 or 3 phase: All Faults			Sustained Faults			Faults (100 mi-yr): Sustained	Temporary	Percent Sustained	sustained station outages per year
	1	2	3	1	2	3				
CAE Report 1/182 - 12/31/86[1]							1.6	1.9	45.7	
AIEE 1952 Report[2]	83	9	8				0.6	5.4	10.6	
IEEE[3] 93 Survey[b]	84	14	2	68	26	6	1.3	0.7	64.3	0.06"

[b]230 kV only, no differentiation of structure type
[c]Of the substation outages reported, only 14% were due to faults in the substation. Therefore, if faults alone considered, the line/station fault ratio would be 56.7

a) What percentage of sustained faults involve only 1 conductor? 2 conductors? 3 conductors?

The data is reasonable consistent in its message on this ratio, despite the paucity of directly applicable results. Most of the data on phase 'involvement, for example, fails to distinguish between transient, temporary, and sustained faults. While the 1952 AIEE data specifically breaks out voltage categories, it does not segregate data by line type. The most recent IEEE survey (1993) did not go any lower than 230 kV, so 230 kV data is listed in the table.

b) What is the expected frequency of sustained faults in each category?

The frequency of sustained faults in Table 5.3.1, expressed in events (100 mi/yr), varies by over two to one. The average value of 1 .O sustained faults per 100 miles per year will be used as a working value: This would mean that a 33 mile line, for example, could expect a sustained fault on the average of once every three years.

c) What is the same data as in a) and b) but for terminal substation equipment failures?

This data is even more varied both in definition and results, than transmission line data. The majority of station-attributed outages are non-fault, non-open, instances, e.g. operator error, relay misoperation, or unknown. No data was found breaking this down by the number of phases involved.

d) What percentage of single phase sustained faults are on the outer conductors?

To date the investigators have been unable to find any data indicating which conductors are most commonly involved in sustained faults. The question is mainly relevant to the spare phase idea since if a normal three-phase line is to operate with one phase out of service, it doesn't matter which phase is involved. It would seem likely that the majority of sustained faults involve the outer phases in an H-frame configuration since they are often due to falling limbs. However barring any demonstration that the spare conductors solution is an attractive move, no further analysis of the issue was made.

Assuming (1) that about 70% of the sustained outages are single phase and that (2) the expected sustained frequency (all faults) will be in the order of one per 100 miles per year, one would expect that either the ability to serve full load with one conductor out of service or to continue serving full load with a sustained ground on one conductor, would drop the sustained outage rate to 0.3 events per 100 miles per year, almost all of which would be two or three phase events. If one could operate with two phases out of service (dc with ground return), the frequency would drop to about .06 outages per 100 miles per year, all of which would be three phase faults. This is about fourteen times longer between outages than with normal 115 kV ac transmission.

5.4 DC TRANSMISSION LINE AND AC LINES ON SAME ROW

Another way of increasing the power density of an existing ac transmission ROW is by adding an HVDC line to an existing ac line corridor. The HVDC line may be on the same towers, over, under or along side an existing ac circuit. Perhaps the term hybrid line would be appropriate. Many factors must be considered when considering such a hybrid arrangement. The mechanical strength, height and general structure of the towers are obvious concerns. However, some important electrical/environmental issues are of paramount importance as well.

When a dc transmission line is constructed above an ac transmission line on the same structures, it is necessary to consider field and ion interactions between the two circuits. These interactions have both system operation and environmental consequences. In addition, consequences of-faults on either the dc and ac circuits must be addressed on the other circuit. Harmonic filter design overvoltages, and design of the relay protection scheme are factors to be considered. Faults which involve both the dc and ac circuit provide their own challenges for detection and clearing.

5.4.1 System Operation Concerns [Ref: *System Effects*]

The presence of ac and dc transmission lines on the same structure results in induction of alternating current in the dc line and dc current in the ac line. This effective interconnection of the ac and dc systems has consequences for the operation of each. These consequences do not preclude operation of ac and dc circuits on common transmission structures, but emphasize areas of engineering study required before construction and operation. Some of these consequences are:

- Effects on dc converter operation caused by induction from the ac line.
- Transformer saturation on the ac system resulting from dc currents coupled from the dc line.
- Relay misoperation due to zero sequence currents induced in the ac lines by transients in the dc lines.
- Consequences of faults involving both the dc and ac circuits.
- Over-voltages on the dc line resulting from ac line faults, and visa versa.
- Stresses on harmonic filters because of the interaction between ac and dc lines.
- Prolonged clearing time for dc line faults because of secondary induction effects from the ac line.

Capacitive and inductive coupling cause ac power frequency current to flow in the dc line. As a consequence of the switching action of the dc converters, other frequency components, including a dc component, are generated. Because of the dc component, a net direct current flows in the converter transformer secondary winding. Even a very small dc component in the converter transformer offsets the transformer core flux sufficiently to cause half-cycle saturation. Extended operation with half-cycle core saturation may affect transformer life. Even if transformer life is not affected, there are several other important well known consequences. Audible noise from the transformer can increase to the point where expensive transformer design modifications or construction of enclosures are required to meet audible noise restrictions. Core saturation produces a full spectrum of odd and even harmonics of high levels compared to characteristic harmonics. The presence of these additional harmonics affects filter design on both the ac and dc sides of the converter, and could be an important factor in telephone interference. The dc component can also saturate current transformers, in addition to the main converter transformer. CT saturation will lead to inaccurate measurements which can affect both converter operation and system protection.

Transposition of the ac line, the dc line, or both, will reduce the induction of ac current into the dc line. DC circuit 60 Hz blocking filters also have been used. DC control could be used to minimize the impact of the ac frequency induction in the dc circuit by imposition of a proper amount of small signal modulation on the dc current.

Small amounts of dc current can be coupled on the ac system by the flow of ions in the air space between the dc and ac lines. DC current can cause saturation of power and instrument transformers on the ac system, leading to increased harmonics, loss of transformer life, and inaccurate measurements.

Operating experience with ac and dc lines sharing a common corridor has shown ac line tripping because of operation of the ground current detection relay during the transition of the dc system from normal metallic return operation to ground return mode operation. Because of the finite resistivity of the earth, even slow transients in the dc circuit may induce relatively large zero sequence currents in the parallel ac lines, which may cause operation of the protection system. The prospect of this type of misoperation must be considered in the design of the ac circuit protection.

A fault caused by a dc pole and an ac phase in contact has several consequences for the ac system. DC current will saturate transformers, resulting in large magnetizing currents and harmonics. Differential relays may trip ac side transformers. Harmonics may result in tripping of capacitor banks. Saturation of current transformers may result in inaccurate measurements and erroneous relay' operations. The ac and direct currents may combine to produce currents with no zero crossing, and result in failure of circuit breakers to clear with subsequent backup breaker operations. Over-voltages are possible due to superimposed voltages with consequent surge arrester operation. Some form of coordination between ac and dc line relay protection will be required to mitigate these problems.

A fault involving only the ac circuit can generate lightly damped fundamental frequency over-voltages, excite resonance conditions in the dc system, and cause direct currents to flow in the converter transformers. The overvoltage on the dc line for a single phase-to-ground fault on the ac line is a function of the inductance of the smoothing reactor. As much as 2.4 per unit overvoltage on the dc line has been calculated for ac system faults when the smoothing reactor resulted in a dc circuit resonance of approximately 120 Hz. Consideration must be given in general to over-voltages on both the ac and dc lines resulting from faults on either the ac or dc line, as overvoltage levels impact insulator design and surge arrester selection. Overvoltages must also be considered in design of 60 Hz blocking filters on the dc side.

These system considerations are presented to define engineering studies which are required for application of dc and ac lines on the same structure from a system operation perspective. They do not preclude such operation, but are matters which must be taken into consideration during the design process.

5.4.2 Environmental Concerns [Ref: *Environmental Effects]*

The presence of the dc line causes a dc component of electric field at the surface of the conductors of the ac line. Likewise, the presence of the ac line causes an ac component of electric field at the surface of the conductors of the dc line. Because conductor corona radio and audiile noise are functions of the maximum electric field at the conductor surface, this additional field component has an effect on radio and audible noise of the hybrid configuration.

Positive corona is the major contributor to radio and audible noise, whether the transmission line is dc or ac. Negative dc fields enhance positive ac transmission line corona activity, increasing radio and audible noise from the ac line. Positive dc fields suppress positive ac transmission line corona activity, decreasing radio and audible noise from the ac line. The relative arrangement of the circuits thus may increase or decrease the overall noise. In foul weather the ac conductors are the predominant source of audible noise, the level being increased if the ac conductors are near the negative dc conductor.

For dc and ac circuits on adjacent towers, the ground level electric field, ion density and ion current density are approximately the same as they would be for both circuits calculated separately. When the dc and ac circuits are constructed on the same structure, there can be an appreciable interaction between them, the details of which depend on the relative layout of the circuits on the structure. If the ac circuit is constructed beneath the dc circuit, there is a shielding of the dc line electric field, ion density, and ion current density at ground level. Increased electric field at the surface of the conductors of the ac line, however, results in increased radio and audible noise from the ac line. In general, the ac conductors behave as active shield wires for the dc circuit by emitting a compensating dc corona which reduces the dc electric field and ion densities. If the dc circuit is constructed beneath the ac circuit, the dc poles act as shield wires for the ac line, reducing the ac electric field at ground level.

One truly interactive effect is human perception of the electric field from a hybrid line. The stimulation of a person by a dc and an ac electric field acting together is considerably greater than for either field acting alone. For example, a typical person in a 15 kV/m ac electric field would experience perceptible, but not annoying sensation. A typical person in a 15 kV/m dc electric field would not be able to perceive the existence of the field. However, in a combined 15 kV/m ac and 15 kV/m dc electric field, a typical person would find it intolerable. This is a true interaction, and must be considered when ac and dc lines are installed in close proximity to each other.

The magnetic field environment of hybrid ac/dc transmission lines is the sum of the fields of each line individually, and no special considerations need to be taken for installation of hybrid lines from a magnetic field standpoint.

As with system effects of ac and dc circuits on the same structure, environmental considerations do not preclude such operation. Rather they are additional matters which must be taken into consideration during the design process.

5.5 SUMMARY

The application of HVDC transmission in existing corridors, either as conversion of ac lines or over/under building with existing ac lines, may present benefits to future transmission developers. This section discussed the unique design issues involved, the solutions for which all are understood and are within current technologies. Of course, the economics of each situation will be the determining factor. The conversion example discussed in Section 5.2 is also one of the economic comparison scenarios studied in Section 6.

6. RELATIVE COST OF HVAC AND HVDC TRANSMISSION OPTIONS

An economic comparison between HVDC and ac transmission is presented in this section. The comparison is made in terms of the classical break-even distance and is done for selected scenarios that represent plausible instances where dc and ac will compete in the future. The quantitative comparisons presented herein were developed using a commercial spread sheet software program (Microsoft Excel) and the estimated cost data given in Section 4. Sample Excel outputs are provided in an Appendix for complete documentation of the methodology employed. In each scenario, the sensitivity of results with several variables are presented.

6.1 HEAVIER LINE LOADING WILL INCREASE LOSSES

The level of transmission loading is expected to increase in the future. Even today, during outages for instance, short transmission lines and subtransmission lines may already be loaded up to thermal ratings. Long high voltage ac lines have not been loaded to thermal ratings for stability reasons, but, the application of FACTs technology may change this. In fact, increased line loading is one of the most important benefits claimed for FACTs technology. The analysis presented in this section indicates that HVDC will be cost competitive with ac, even for relatively short lines, iftransmission can be loaded close to thermal ratings.

Transmission losses increase as the square of loading, so line losses would increase dramatically if loading is increased to thermal ratings. Losses while operating at the thermal rating are typically five times the losses at surge impedance loading. Also, if line loading increases to thermal limits, lower voltage circuits will be used to transmit bulk power. The percent losses are, of course, higher at lower voltage levels. Losses could thus increase both because lines will be more heavily loaded and because lower voltage lines will be used to transmit more power. The economics of transmission projects will therefore depend much more heavily upon the evaluated cost of losses. Even today the evaluated cost of losses sometimes equals the installed cost for power system equipment such as static var systems.

The line losses for direct current transmission are lower than for comparable alternating current transmission. Assuming the same transmitted power, conductor resistance and peak voltage, the transmission losses for an HVDC bipole (two conductors) will be about 75% of the losses for three-phase ac transmission, as shown in Appendix D. 1. The difference in losses is even greater if the difference between the ac and dc line resistance (due to skin effect-which increases with conductor size-and core losses) is included in the analysis. For typical transmission line conductors the ac resistance will exceed the dc resistance by 1.5% to 11% because of skin effect. For typical transmission line conductors core losses cause an additional 1% to 4% increase in ac resistance depending upon the level of loading.[1] For the analysis herein it was assumed that the ac resistance of a conductor is 5% higher than the dc resistance. Direct current bipole transmission line losses including skin effects and core losses are typically 65%

to 73% of the three phase ac line losses. This assumes that the ac and dc peak voltage's are the same, the conductor type is the same and the loading is the same.

Seen another way, with the same losses (heating) per conductor, the dc bipole (2 conductors) can transmit between 96% and 101% of the MVA transmitted by the three-phase ac line. The thermal limit on transmitted **MVA** is therefore almost the same for a dc bipole and a three-phase ac line with the same peak voltage and conductor type. The thermal capacity for both will, of course, depend upon ambient temperature, wind speed, loading duration, previous levels of loading, etc. The actual value for thermal capacity is therefore somewhat subjective; in this analysis thermal capacities for different conductor types have been assigned on a consistent basis.

Reactive power flow in an ac line will use up some of its thermal capacity. As line loadings increase, the reactive losses will also increase, necessitating the use of capacitive compensation, even in shorter lines than would normally be expected to need such measures. With a dc line the entire capacity is available for active power flow.

6.2 THE BREAK EVEN DISTANCE - BEVISITED

For fair comparison with ac, the lower dc transmission line losses must be weighed against the dc converter losses, which do not exist for the ac case.[1] There is a transmission length for which the lower dc transmission cost pays for the higher dc terminal (converter) cost. This distance is referred to as the break even distance. The break even distance, as illustrated in Figure 3.2 earlier, is a classical way of characterizing the viability of HVdc transmission compared to ac transmission. For longer distances HVdc is less costly; for shorter distance ac is less costly.

Using present worth analyses, the evaluated cost of losses can be combined with installation cost to calculate "total cost". Since the line will not always be at peak load the load duration must also be considered. A loss factor of 0.4, (the ratio of average losses over a year to losses at peak load) is assumed for this analysis. The break even distances would be less for higher loss factors. In Tables D.3.1 and D.3.2 of Appendix D.3, separate break even distances are shown for the installed cost., for the energy losses, and for the "total cost". The break even distance for "total" cost will depend heavily upon the expected level of line loading since losses will dominate cost at heavier load and installed cost will be more important for lighter loads.

Table 6.1 shows break even distances based upon "total cost" for selected ac and HVdc transmission options. That table combines the results in Tables D.3.1 and D.3.2 of Appendix D. The present worth (of losses) analysis used to calculate the break even distance is based upon

[1] For some conductors, which are used mostly for lower voltage circuits, the core losses increase dramatically at heavy loading. At 75% of rating, and a conductor temperature of 50 degrees Centigrade, the ac resistance for a single layer ACSR is 1.4 times the dc r&stance. [Ref: Conductors]

an effective rate of return of 8% (the difference between the expected return on investment and inflation) and a life expectancy of 30 years. With those assumed data, used through Section 6.4, the losses are worth $2,080 per KW. Section 6.5 contains results with the value of losses varied from zero to $2,080/KW.

Appendix D.2 contains the equations used to calculate the present worth of losses. Tables D.3.3 and D.3.4 in Appendix D.3 show the, cost assumptions used for the analysis. Except for the HVdc converter, typical costs are assumed (see Section 4 or Appendix D). The converter costs are assumed to be 50% of todays costs, which are summariized in Section 4.4.

Figures 6.2 and 6.3 show the sensitivity of the break even distance to converter costs for the ac and HVdc transmission options and loading levels indicated in Table 6.1 and depicted in Figure 6.1. In Figure 6.2 and 6.3, 1.0 p.u. cost equals today's converter cost. To calculate the break even distances for Figure 6.2, the peak line loading assumed are at the high end of that typically experienced during normal operation today. The break even distances in Figure 6.3 were calculated for peak line loading at the ac thermal limit. The HVdc converter MVA ratings and ac substation equipment ratings were assumed to equal the peak line loadings in arriving at the results in Figures 6.2 and 6.3.

Table 6.1 gives two break even distances for each level of loading; labeled "Without comp." and 'With comp." where "comp." corresponds to reactive compensation. The former is the break even distance computed without including the cost of additional var support which will be needed to maintain reasonable voltages for heavy line loading. The "With comp." break even distance was calculated including the cost of sufficient var support to compensate 100 % for the reactive power absorbed by the line at peak loading. The cost of var support was assumed at $15/kvar. This cost falls between the costs of conventional series compensation and conventional shunt compensation. To permit loading up to thermal ratings some of the var support would most likely need to be augmented by FACTs devices. The added costs for FACTS controllers were not included.

The break even distance was calculated for seven cases. For each case two levels of load (unity power factor) were considered. For most cases the HVdc converter MVA ratings and ac substation equipment MVA ratings are assumed to equal the peak line loading. For Cases 3,6 and 7 the break even distances were also calculated for converters and substation equipment rated to handle peak load with one circuit out. Table D.3.5 in Appendix D.3 shows the installed cost and losses for each transmission configuration. The results in Table 6.1 are valid for the "reduced-cost Hvdc converters - 50% of today's cost) while Figure 6.2 and 6.3 show how these results vary with converter costs.

Case 1. In this case, a 408 kV DC bipole is compared to a 500 kV single circuit ac line, as depicted in Figure 6.1 a. Presently 1000 MW is considered a heavy load for both transmission options. The peak voltage is the same for both options and the same conductor size was assumed. The thermal rating for the ac line, typical 2000 MW, is therefore almost the same as for the HVDC bipole. The right-of-way width for the dc-bipole was assumed to be about 100 feet compared to 200 feet for the 500 kV ac line.

For 2000 MW loading the break even distance, based upon reduced-cost converter and substation installed cost, var support and losses, is 248 miles. At present day heavy loading levels, 1000 MW, installed cost largely determines the break even distance of 266 miles.

Case 2. In this case, a 281 kV DC bipole is compared to a 345 kV single circuit ac line as shown in Figure 6. lb. The thermal rating of a 345 kV single circuit ac line is normally around 1000 MVA. Again the HVdc alternative is chosen to have the same peak voltage as the ac alternative and the conductor sizes are assumed to be the same. The thermal rating for the HVdc bipole circuit is therefore almost the same. The right-of-way width for the Hvdc bipole was assumed to be 135 feet compared to 150 feet for the 345 kV ac line.

For a peak load of 1000 MW with reduced-cost converters rated for 1000 MW the "total cost" (installed cost + losses + var support) of the 345 kV line will exceed the total cost of the Hvdc bipole iftransmission distances exceed 193 miles. If the peak loading and converter ratings are 500 MW, 50% of the dc or ac lines thermal rating, the break even distance will be 196 miles.

Case 3. As illustrated in Figure 6.1 c, a double circuit 230 kV ac line is compared to the 281 kV dc bipole considered in Case 2. A single phase ac line fault (the most common kind) will normally result in power interruption for all three phases. It may therefore be necessary to use two ac circuits instead of one ifreliability is important. One dc-bipole with ground return may however be sufficient since a line fault on one pole will not normally cause power interruption on the other pole. The double circuit ac line is selected to have approximately the same thermal capacity (1000 MVA for both circuits) as the dc option. The ac and dc alternatives also have approximately the same (500 MVA) thermal capacity with a single contingency outage. The right-of-way requirements of the AC and DC options are also similar.

For transmission distances greater than 90 miles the total cost (installed cost + losses + var support) of the 2-230 kV circuits operated up to 1000 MW will exceed the total cost for the dc-bipole (including reuced-cost converters rated for 1000 MW). For peak transmission loading and converter ratings of 500 MW, the break even distance for Case 3 is 163 miles. For some applications, however, a line may be designed so the system can transmit peak power with a single contingency outage. Depending upon the number of parallel lines, the dc converters or ac substation equipment might therefore be rated for as much as 1000 MW to accomplish this. The break even distance with 500 MW peak loading and 1000 MW converters is 275 miles.

Case 4. In this case, a 408 kV dc monopole with ground return is compared with 345 kV single circuit ac transmission as depicted in Figure 6.1 d. Outage of a dc monopole would have approximately the same impact on the system as outage of a single circuit ac line.

The total cost of the 345 kV ac line (with var support) operated up to its thermal rating (1000 MW) will exceed the cost of the dc monopole (reduced-cost converters rated for 1000

MW) when the transmission distance is greater than 140 miles. If the maximum loading is "only" 500 MW, and the converters and var support are sized accordingly, the break even distance will be 151 miles.

Case 5. To reduce transmission losses, a double circuit ac line could be converted into transmission circuits for 3 bipoles of Hvdc as noted in Figure 6.1e. This may only require changing the insulators and adding the converter stations. The conversion might be done while still operating with ac so the down-time could be minimal. In this case, the double circuit 230 kV ac line (188 kV peak line to ground, 1000 MW thermal capacity) is compared to 3-188 kV dc bipoles. The 3 bipoles are assumed to use towers and conductors that were previously used by a double circuit 230 kV line.

For transmission distances greater that 124 miles the savings in losses and ac var support will more than pay for reduced-cost HVdc converters rated for 1000 MW if the peak line loading is 1000 MW. For peak loading and converter ratings of 500 MW the break even distance is 254 miles.

Case 6. This case is a variation of Case 5 in that an existing double circuit ac line is converted to three HVdc bipoles to increase transmission capacity with minimal impact on the transmission corridor. As illustrated in Figure 6. 1f, this case compares the described conversion to adding a third ac circuit (if this is feasible) to the existing double circuit ac line. The thermal ratings of both options are about equal to 1500 MW and capacity will also be almost the same for both options with a first contingency outage. Case 6 compares the total cost of adding a single 230 kV ac circuit to the cost of converting an existing double circuit 230 kV ac line to three 188 kV dc bipoles.

For peak loading of 1500 MW (the approximate thermal limit of the ac & dc lines) with reduced-cost converters rated for a total of 1500 MW at each terminal the dc alternative is less expensive if the line length is greater than 151 miles.

For peak loading of 1000 MW with converters rated for 1000 MW at each terminal, the dc alternative in this case is less expensive than that of the ac if the line length is greater than 192 miles.

For some applications, however, a line must be designed so the system can transmit peak power with a single contingency outage. If there are no other parallel lines, the dc converters or ac substation equipment may therefore be rated for as much as 1500 MW to accomplish this. The break even distance with 1000 MW peak loading and three 500 MW converters at each terminal is 260 miles. Increasing the converter rating does not raise the distance in the same proportion because the costs are dominated by losses.

Case 7. This final case compares ac and dc underground or underwater cables. As illustrated in Figure 6. lg, two three phase 345 kV ac circuits are compared with a ±400 kV dc bipole with a part-time ground or sea return. The thermal capacity of both options is 1000 MW.

With reduced-cost HVdc converters rated at 1000 MW and peak loading of 1000 MW the "total cost" of the ac option exceeds the total cost of the dc option for distances greater than 28 miles. Since a 345 kV ac cable is technically impractical for uncompensated distances longer than 18 miles (30 km per Figure 7. 1), the economic comparison in this case is moot for submarine cables. However, ifunderground ac cables are equipped with shunt reactors at strategic points along their length (the costs for which are not included herein), HVdc cables may be more economical than ac cables.

For peak transmission cable loading and converter ratings of 500 MW the break even distance for Case 7 is 17 miles. However, a cable system. probably would never be designed this way since the cables would be very underutilized. In some cases, however, a cable system might need to transmit peak power with a single contingency outage. If there are no other parallel cables the converters or ac substation equipment must then be rated for 1000 MW, not 500 MW. The break even distance with 500 MW peak loading and 1000 Mw converters is 29 miles. The break even distance for cable does not increase significantly when loading is lower because the ac cable dielectric losses, unlike most other losses, do not decrease with current loading.

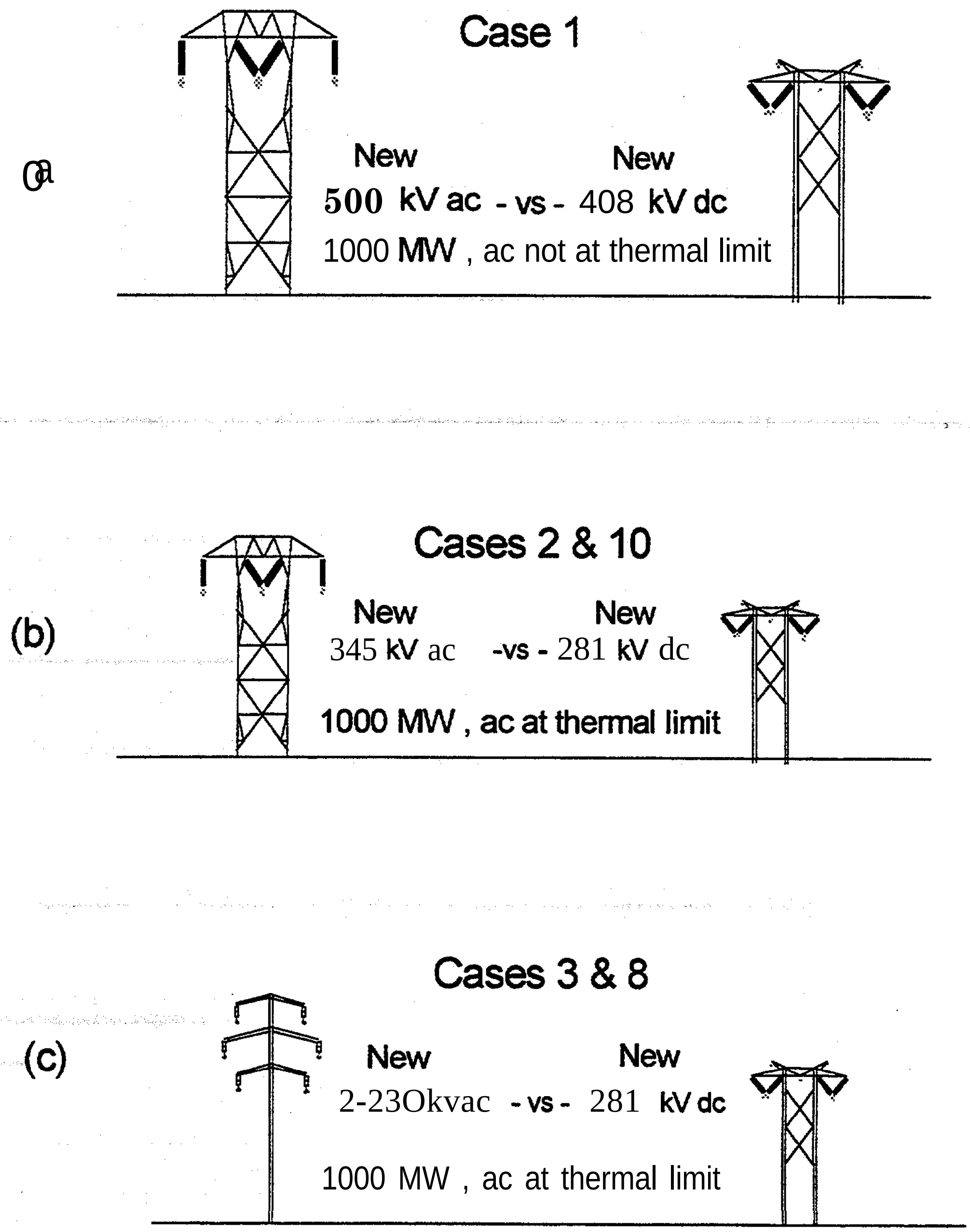


Figure 6.1 Configurations Compared in Break Even Analysis

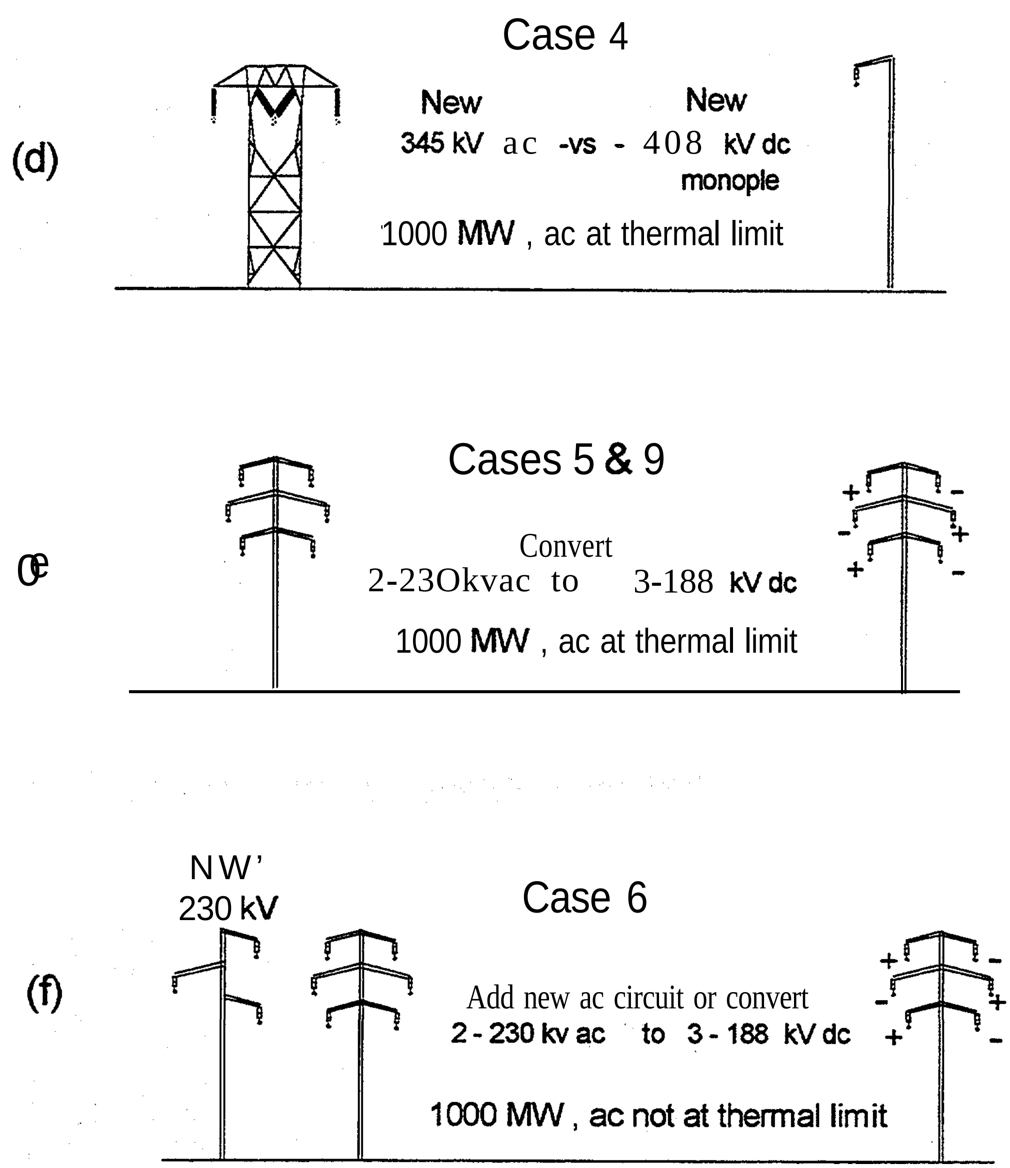
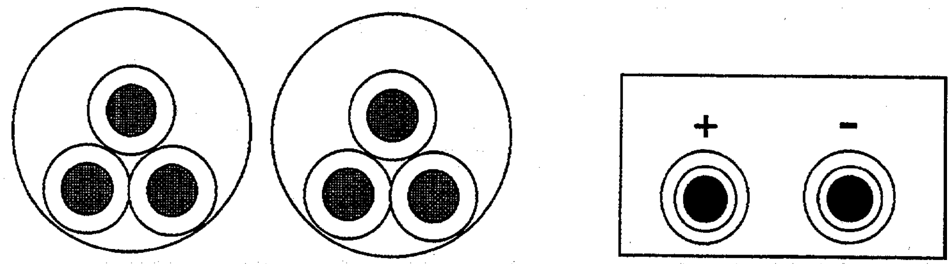


Figure 6.1 Configurations Compared in Break Even Analysis
- continued -

Case 7

(g)



2 - 345 kV 3 phase ac cables -vs - 2-400 kV dc cables earth or sea return

Figure 6.1 Configurations Compared in Break Even Analysis
- continued -

TABLE 6.1. TRANSMISSION DISTANCE IN MILES FOR WHICH HVDC BECOMES LESS COSTLY THAN THE AC ALTERNATIVE (CALULATED USING 50% OF PRESENT-DAY CONVERTER COSTS)

CASE	ac line Voltage & circuits	dc line Voltage & circuits	Comments	Converter Rating	Peak Loading	Break-Even Distance (miles)	
				MW	MW	Without Comp.	With Comp.
1	1 - 500 kV	1 - 408 kV bipole	AC & DC line thermal rating ≈ 2000MW	2000	2000	291	248
			Todays typical loading is up to 1000 MW.	1000	1000	274	266
2	1 - 345 kV	1 - 281 kV bipole	AC & DC line thermal rating ≈ 1000MW	1000	1000	219	193
			Todays typical loading is up to 500 MW.	500	500	200	196
3	2 - 230 kV	1 - 281 kV bipole	AC & DC line thermal rating ≈ 1000MW	1000	1000	100	90
			With ≈ 500 MW 1st contingency capacities	1000	500	294	275
			W i i ≈ 250 MW 1st contingency capacities	500	500	174	162
4	1 - 345 kV	1 - 408 kV monopole	AC & DC line thermal rating ≈ 1000MW	1000	1000	154	140
			Zero MW for 1st contingencv outage.	500	500	153	151
5	2 - 230 kV	3 - 188 kV bipoles	AC line thermal rating ≈ 1000MW	1000	1000	139	124
			AC & DC use identical towers & wires	500	500	278	254
6	3 - 230 kV	3 - 188 kV bipoles	AC & DC line thermal rating ≈ 1500MW	1500	1500	191	151
			With ≈ 1000 MW 1st contingency capacities	1500	1000	309	260
			With ≈ 500 MW 1st contingency capacities	1000	1000	229	192
7	2 - 345 kV 3-phase cables	2 - 400 kV bipole cables	AC & DC line thermal rating ≈ 1000MW	1000	1000	28	28
			With ≈ 500 MW 1st contingency capacities	1000	500	29	29

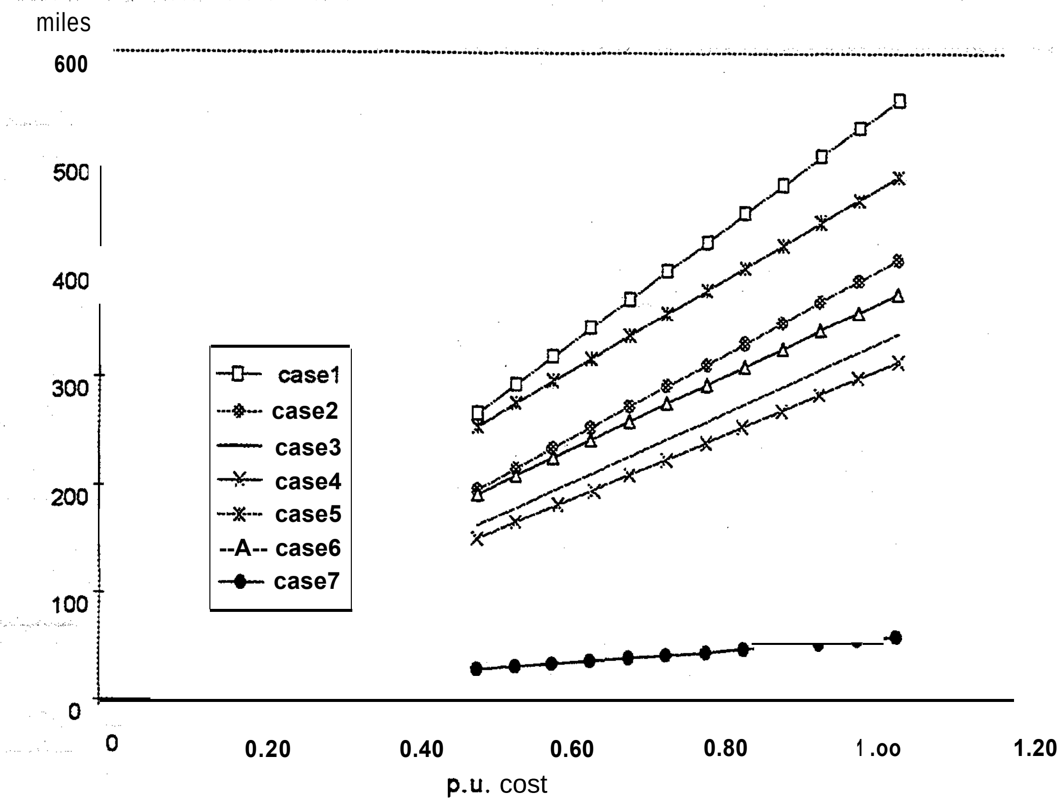


Figure 6.2 Break Even Distance vs Converter Cost for Heavy Line Loading Consistent With Today's Practice - 1 p.u. Equals Today's Converter Costs

Legend for Figure 6.2 above

Case	ac Line Voltage & circuits	dc Line Voltage & Poles	Loading MW
1	1 - 500 kV	1 - 408 kV bipole	1000
2	1-345kV	1 - 281 kV bipole	500
3	2 - 230 kV	1 - 281 kV bipole	500
4	1-345kV	1 - 408 kV monopole	500
5	2 - 230 kV converted	to 3 - 188 kV bipoles	500
6	3rd - 230 kVor convert	to 3 - 188 kV bipoles	1000
7	2 - 345 kV 3 ph cables,	2 - 400 kV bipole cables	500

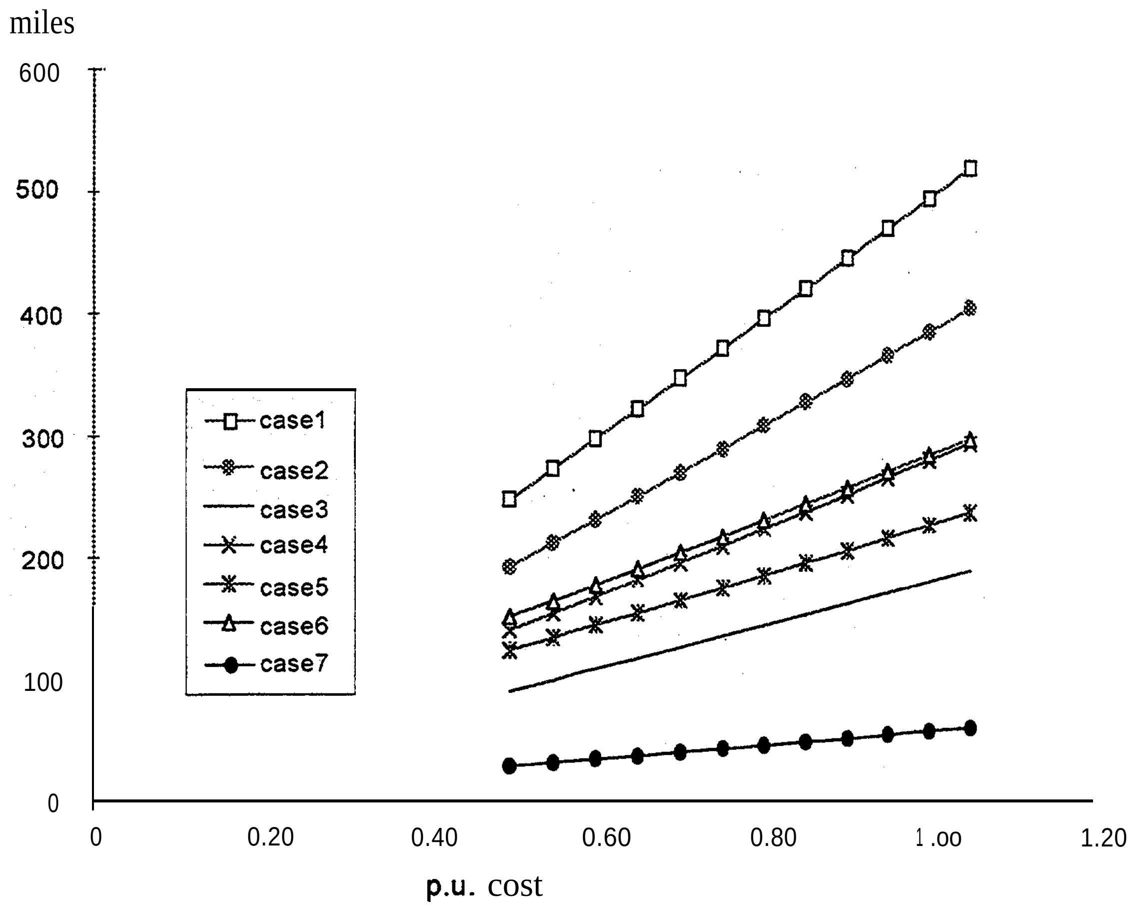


Figure 6.3 Break Even Distance vs Converter Cost for Peak Line Loading at Thermal Limits - 1 p.u. Equals Today's Converter Costs

Legend for Figure 6.3 above

Case	ac Line Voltage & Circuits	dc Line Voltage & Poles	Loading MW
1	1 - 500 kV	1 - 408 kV bipole	2000
2	1 - 345 kV	1 - 281 kV bipole	1000
3	2 - 230 kV	1 - 281 kV bipole	1000
4	1 - 345 kV	1 - 408 kV monopole	1000
5	2 - 230 kV converted	to 3 - 188 kV bipoles	1000
6	3rd - 230 kVor convert	to 3 - 188 kV bipoles	1500
7	2 - 345 kV 3 ph. cables	2 - 400 kV bipole cables	1000

6.3 VARIATION IN BREAK EVEN DISTANCE WITH LOADING

For each case shown in Table 6.1, Figure 6.4 shows the break even distance for different levels of peak load. In this figure, 1 .O per unit load equals the ac line's thermal capacity. The cost of HVdc converters was assumed to be $50/KW/terminal; half of today's typical cost.

The break even distance for low voltage lines loaded to their thermal limit is smaller than the break even distance for high voltage lines. This is true because:

1. Line losses as a percentage of loading decrease as the voltage increases.
2. The break even distance is largely determined by the cost of losses when the lines are loaded to thermal rating.

It is also noted that when lines are loaded near their thermal limits, the break even distance decreases as load increases. This is true because:

1. Losses increase as the square of loading.
2. Converter costs are proportional to peak loading.

Interestingly, when loading becomes low enough the break even distance can also decrease with decreasing load. This is noticed for the 500 kV and 345 kV lines and is true because:

1. Installed cost of a line largely determines the break even distance.
2. As loading decreases, converter costs also decline, but the line cost remains constant.

That is, the Hvdc line becomes more competitive if the line will be underutilized.

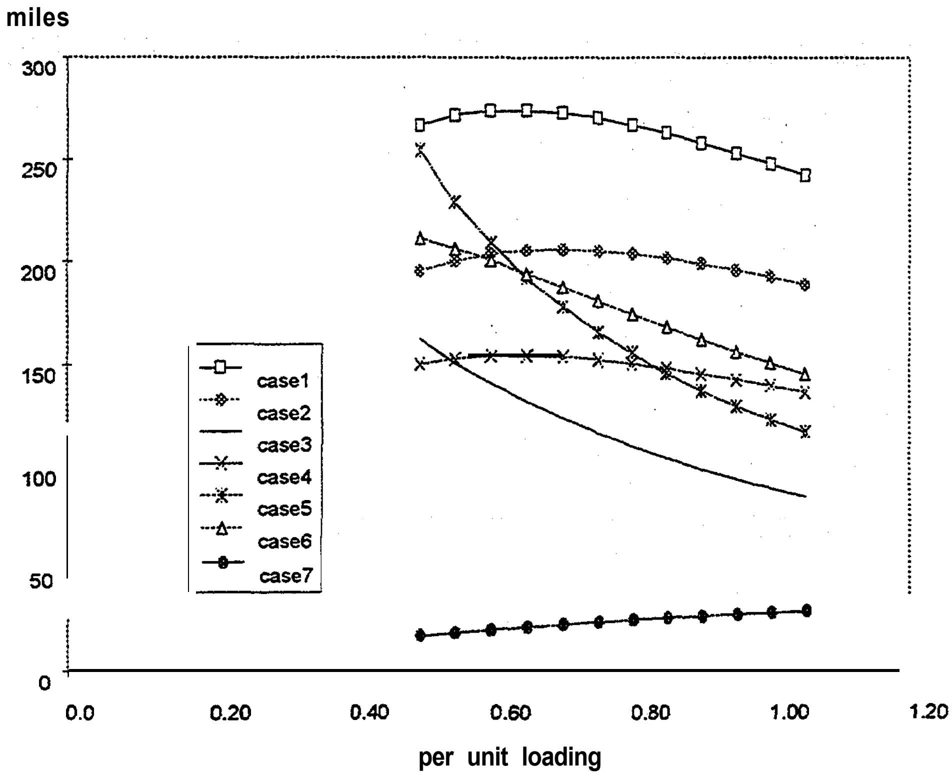


Figure 6.4 - Break Even Distance vs Peak Line Loading Assuming The Converter Rating Equals the Peak tine Loading - 1 p.u. Loading Equals the tine's Thermal Capacity

Legend for Figure 6.4 above - Using "todays" converter costs = $1001 KW/terminal

Case	ac Line Voltage & Circuits	dc Line Voltage & Poles
1	1 - 500 kV	1 - 408 kV bipole
2	1 - 345 kV	1 - 281 kV bipole
3	2 - 230 kV	1 - 281 kV bipole
4	1 - 345 kV	1 - 408 kV monopole
5	2 - 230 kV converted	to 3 - 188 kV bipoles
6	3rd - 230 kV or convert	to 3 - 188 kV bipoles
7	2 - 345 kV 3 ph. cables	2 - 400 kV bipole cables

6.4 CONTINGENCIES AND THE VALUE OF LOST TRANSFER CAPACITY

The import of economy power into some metropolitan areas and inter-regional transfers are limited even today by first contingency transfer capability. For multiple outages, it may be permissible to shed load but for more common occurrences such as single circuit outages load shedding is not a viable option Since the system must be designed to survive a first contingency outage, the power import capability during normal operation is often determined by the transmission capability with the worst single contingency outage.

The value of first contingency transfer capability is difficult to determine and is very situation-dependent. Iftransfer capability is not sufficient, it may be necessary to provide local peaking power even though sufficient generation is available elsewhere. A gas turbine is commonly used to provide peaking capacity, so first contingency transfer capacity might be worth as much as the cost of a gas turbine (approximately 350$/kW). However, in most cases the cost that can be attributed to the transfer capacity lost for a particular outage is somewhat less. The gas turbine may provide peaking capacity for more than one equally critical outage so its $/kW cost may not always be associated only with one most critical outage. Measures that only increase transfer capacity for a specific contingency are therefore less valuable. A gas turbine may also provide benefits other than peaking which justify some of its cost or it may partially replace new generation outside the load area.

Nevertheless, transfer capacity with a single contingency outage can have significant value. With new right-of-way becoming scarce, the transfer capability remaining after a single contingency outage could become more valuable. Economy import during normal operation can be limited by the need to survive all first contingency outages. Therefore, there may be an energy cost differential ($/kW-Hr) associated with a first contingency constraint as well as the $/KW costs associated with lost capacity as discussed above. For this analysis it was assumed that the present worth of the energy cost differential caused by a first contingency constraint is lumped into an average $/kW cost for lost transfer capacity.

Previous Sections 6.2 and 6.3 compared the installed costs and losses for several ac and HVDC alternatives and concludes that HVDC may be cost competitive with ac even for relatively short distances if, as many suggest, transmission is loaded close to thermal limits. This section extends the previous analysis to include the value of transfer capability during single contingency outages. The equipment cost and characteristics used for this analysis are documented in Section 4 and were discussed earlier in Section 6. Section 6.4.1 sets the stage by first comparing two ac alternatives. Section 6.4.2 continues the comparison of ac and HVDC with today's converter costs - about $100/KW/terminal - and then varies that cost as in previous sections to derive break-even distance values.

6.4.1 Single Circuit ac versus Double Circuit ac Lines

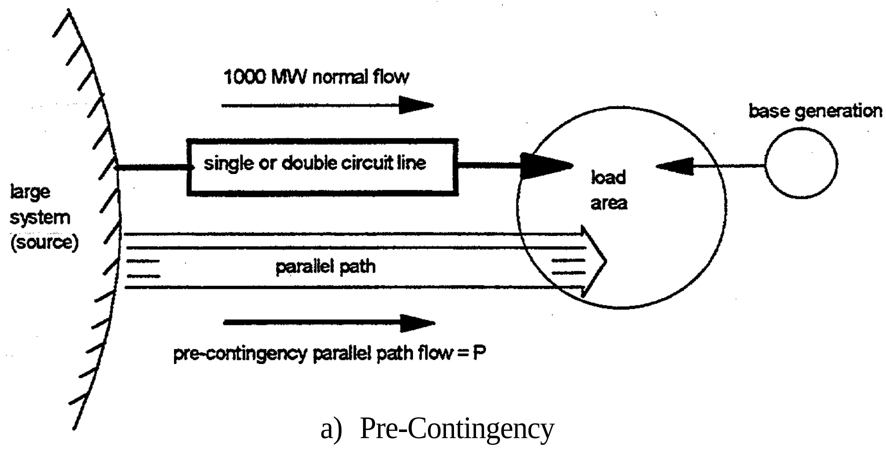
A comparison considers a single circuit 345 kV line and a double circuit.230 kV line. During pm-contingency operation, the 345 kV line is assumed to be loaded to its thermal rating (approximately 1000 MW) with the aid of reactive compensation sufficient to attain the appearance of surge impedance loading, SIL conditions. Similarly, the double circuit 230 kV line is assumed to be loaded to 1000 MW, approximately its thermal capacity. Again, sufficient reactive compensation is assumed to attain equivalent SIL conditions. Figure 6.5a illustrates the pre-contingency conditions where the subject line delivers 1000 MW to the load area and the parallel system, if any and the local generation serve the remainder of the demand.

Consider the contingency loss of one circuit of the subject line. Of course, the loss of the single circuit 345 kV line yields zero post-contingency transfer capacity. With one 230 kV circuit out of service the remaining 230 kV circuit is assumed to be capable of 500 MW transfer. Figure 6.5b illustrates the post-contingency conditions following the loss of the single circuit 345 kV line. The replacement capacity is shared between a "peaking generator" serving fraction "f' of the lost 1000 MW capacity and the parallel system picking up (l-f)x1000 MW. Figure 6.5c shows that only 500 MW must be shared by the parallel system and the "peaking generator?' for loss of one 230 kV circuit. The cost of the replacement capacity will vary due to numerous conditions but is assumed to vary from zero to $300/kW for this example.

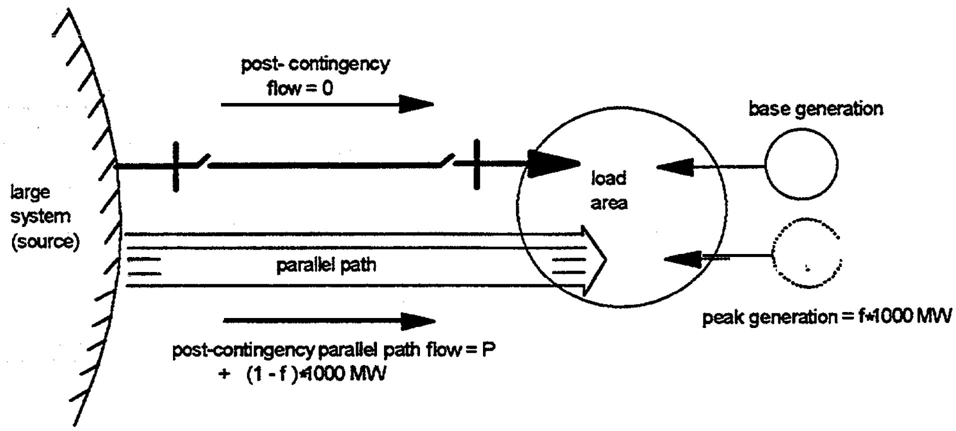
It would seem that double-circuit ac lines should be more competitive (compared against single circuit lines at a higher voltage levels) if the costs of replacing the lost transfer capacity during an outage is considered in the evaluation. However, there is a maximum line length beyond which this does not hold and that value depends on the cost of replacement capacity. For example, the total costs for a 345 kV single circuit line and a 230 kV double circuit line are plotted versus length in Figure 6.6 with different replacement capacity costs. The installed cost and the present worth of future losses plus the cost of the peaking capacity are plotted on the vertical axis. The three curves for each line represent different prices for the capacity lost with a circuit out.

If lost transfer capability with a circuit out has no value ($0/kW) the 345 kV lime in this example is more economic than a double circuit 230 kV line for any line length. At the other extreme considered, where lost transfer capability is valued at 300 $/kW, the single circuit 345 kV line will be more economic only for distances *greater than* (about) 250 miles. Beyond 250 miles in length, the higher cost per mile of the double circuit line offsets that alternative's lower post-contingency replacement capacity cost so the single circuit 345 kV line becomes the least-cost alternative. For $150/kW replacement capacity cost, the single circuit 345 kV line is competitive beyond only 125 miles.

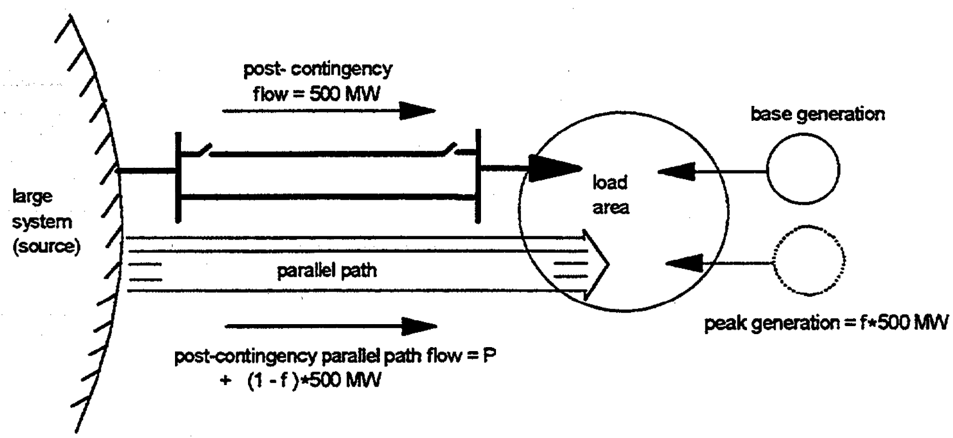
Consideration of the potential cost of replacement capacity can have a profound effect on the economic choice of transmission line additions. The following section applies this added dimension to the comparison between ac and HVDC alternatives considered in earlier sections.



a) Pre-Contingency



b) Post - Contingency for single circuit line



c) Post - Contingency for double circuit line

Figure 6.5 - Effect of circuit outage; single 345 kV line versus double circuit 230 kV line

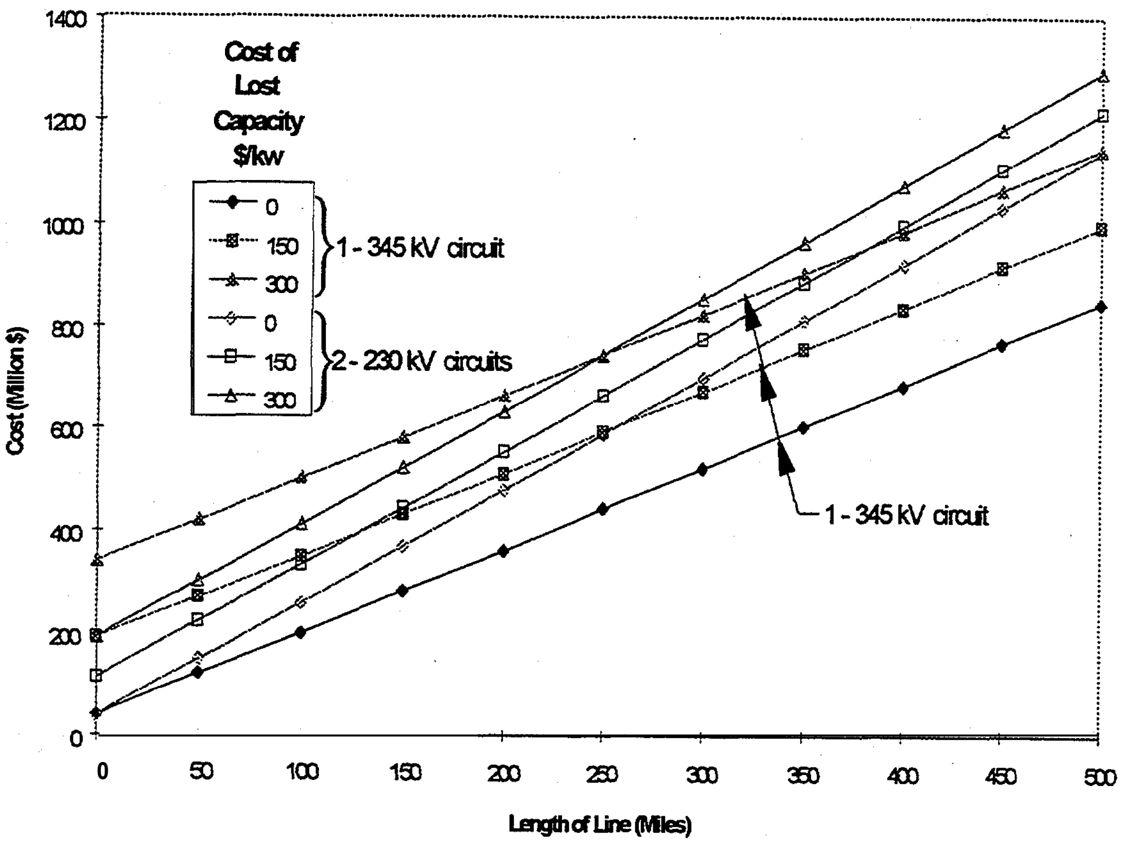


Figure 6.6 - Total cost vs. length - Single 345 kV ac (solid symbols) versus double circuit 230 kV ac at 1000 MW max. load. Cost includes: construction of substations, line, var compensation, present worth of losses and peaking capacity costs. The peaking capacity valued at $/kW prices in legend.

Legend:

Capacity cost $/KW	Break-even distance *
0	0 mi.
150	130mi.
300	250 mi.

* Distance at which the two lines costs are equal

6.4.2 Effect of Replacement Capacity Costs on HVDC -vs- ac Break-even Distances

This section again compares power supply cost for various ac and HVDC transmission line configurations. The comparison includes installed cost, cost of real and reactive losses (as before) plus *the cost of peaking capacity neededfor single circuit outages*. Three cases are considered here; Cases 8, 9, and 10:

Case 8. A double circuit 230 kV ac line is compared with a single ±281 kV HVDC bipole which has the same thermal capacity as the ac line but a higher peak voltage. This is structurally the same as Case 3 of Section 6.2 as illustrated by Figure 6. lc.

Case 9. A double circuit 230 kV ac line is *converted* to three ±188 kV HVDC bipoles utilizing the same conductors size and operating at the same peak voltage; but having a higher thermal capacity than the ac line. This is similar to Case 5 in Section 6.2 and is illustrated by Figure 6. le. In addition to the 1000 MW scenario, an additional variation considered here considers the utilization of the line's added thermal capacity under dc operation by increasing the ratings of the converters to a combined rating of 145 1 MW for the three bipoles.

Case *10.* A single circuit 345 kV ac line is compared with a ±281 kV HVDC bipole that has the same thermal capacity, conductor size and peak voltage as the ac line. While the HVDC line could have been a conversion, this case considers two new lines. This is the same as Case 2 in Section 6. I and is illustrated by Figure 6. lb.

The comparisons are for a pre-contingency maximum line (single ac, double ac, single bipole or multi-bipole) loading of 1000 MW. This is effectively the thermal limit for all options except one variation considered within Case 9 where some excess thermal capacity (451 MW) on the HVDC system is held in reserve for contingencies. These "thermal limits" are, of course, approximate limits. Actual thermal limits depend on a variety of factors including ambient temperature, wind speed and duration of peak loading, all of which are variable. For simplicity in this analysis, the thermal limits were assumed to be constant values. Never-the-less, it is anticipated that competitive pressures and transmission expansion constraints will make operation at or near thermal loading necessary in future years.

As noted before, normal (pre-contingency) and post-contingency conditions for single and double circuit ac alternatives are illustrated in Figure 6.5. The HVDC configurations studied herein range from one to three bipoles. Figures 6.5a and 6.5b can represent pm-contingency and post-contingency conditions simply by replacing the ac line with the single or multipole HVDC configuration. Considering single pole outages only, there are several possible post-contingency transfer capacities for a given bipole. This will depend upon whether or not a return current path is provided.

The possibilities considered are :

- zero if there is no provision for return current
- ½ the bipole converter rating if a return path with sufficient capacity is available; (options are earth/sea return if permitted or a partially insulated "ground' conductor)
- the entire bipole rating if there is a fully insulated spare conductor provided with suitable switching to connect it in place of the faulted pole.

An HVDC bipole line with a spare conductor would of course be very similar to a three-phase AC line and might in fact be the result of converting an existing ac line for dc operation. The most cost effective dc option will depend upon the cost of peaking power, the need for peaking power during an outage, the line length and the feasibility of ground or sea return. If a converter larger than that required for normal loading is used to get additional peaking power - a variation considered in Case 9 - the cost of the converter must also be considered. These factors are all important when ac options are compared against HVDC options.

Except in one variation of Case 9, first contingency outages considered were only <u>network</u> outages, that is excluding generator outages. That exception in Case 9 considers the use of reserve HVDC capacity (post-outage HVDC thermal capacity - 1000 MW) to cover loss of parallel system capacity or loss of local generation. Unless noted, contingencies are the loss of one of the "new" ac lines or the "new " or "converted" dc lines. Therefore, for this analysis, the peaking capacity (MWs) required for an outage on the line itself is assumed to equal the difference between peak load for the line (1000 MW) and the capacity of the "new or converted" transmission remaining after the outage. For ac alternatives the capacity will drop from 1000 MW to either 500 MW for a double circuit line or zero for the single circuit line. The amount of post-contingency capacity will vary for the HVDC schemes as will be described as they are encountered. Meanwhile, Figure 6.7 attempts to visualize the various HVDC scenarios studied.

Since the value of transfer capacity ($/MW) is situation dependent, this analysis includes results for a range of values. Also, it should be noted that today's HVDC converter costs were used for results in Figures 6.8, 6.9, and 6.10.

Case 8: Double Circuit 230 kV ac vs. a ±281 kV HVDC Bipole

These circuits are the same as those in Case 3 in Section 6.2 . Figures 6.8, 6.9, and 6.10 show the cost for a double circuit 230 kV AC line and a ±281 kV DC bipole. These costs include not only the installed cost and present worth of future losses but also the cost for the loss of transfer capability during a single circuit outage. The double circuit ac line is selected to have approximately the same thermal capacity (1000 MVA total for the two circuits) as the HVDC option. Peak loading of 1000 MW is assumed. The lost transfer capacity is evaluated as follows:

Figure	Value of Lost Transfer Capacity
6.8	100$/kW
6.9	200$/kW
6.10	300$/kW

The post-contingency capacity of the three alternative configurations in Fig. 6.7a are:

Transmission Configuration	MW Capacity Before Contingency	MW Capacity after one ckt. or pole is lost
Double Circuit 230 kV ac line	1000 Mw	500 Mw
±28 1 kV HVDC Bipole w/ground return	1000 Mw	500 Mw
±28 1 kV HVDC Bipole w/spare pole wire	1000 Mw	1000 Mw

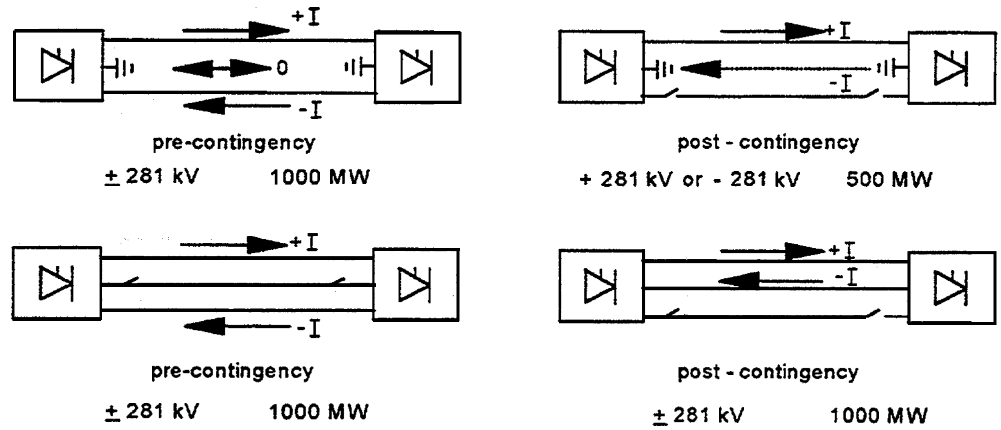
Ground return in this context means the return current uses earth as a conductor, since a metallic return (partially insulated return conductor) is not provided for in the cost of the HVDC line. This may not be considered a viable operating configuration if only limited time in that mode can be tolerated. As discussed in a companion report on Monopolar Operation, the electrodes may not be capable of many hours of full current operation (many systems are not) or restrictions may have been placed on the use of ground return operation to avoid corrosion of underground facilities and possible dangerous step-and-touch voltages. The use of metallic return is considered Iater with Case 9. For this analysis, ground return was considered acceptable until the faulted pole line can be restored to operation.

The ac - vs - HVDC break-even distance is 180 miles (same as Case 3, Figure 6.3 at 1 p.u. converter costs) for the HVDC with a suitable ground return capacity. This does not depend upon the value of lost transfer capacity since the transfer capability of ac with one circuit out equals the transfer capability of a single pole of HVDC (with ground return).

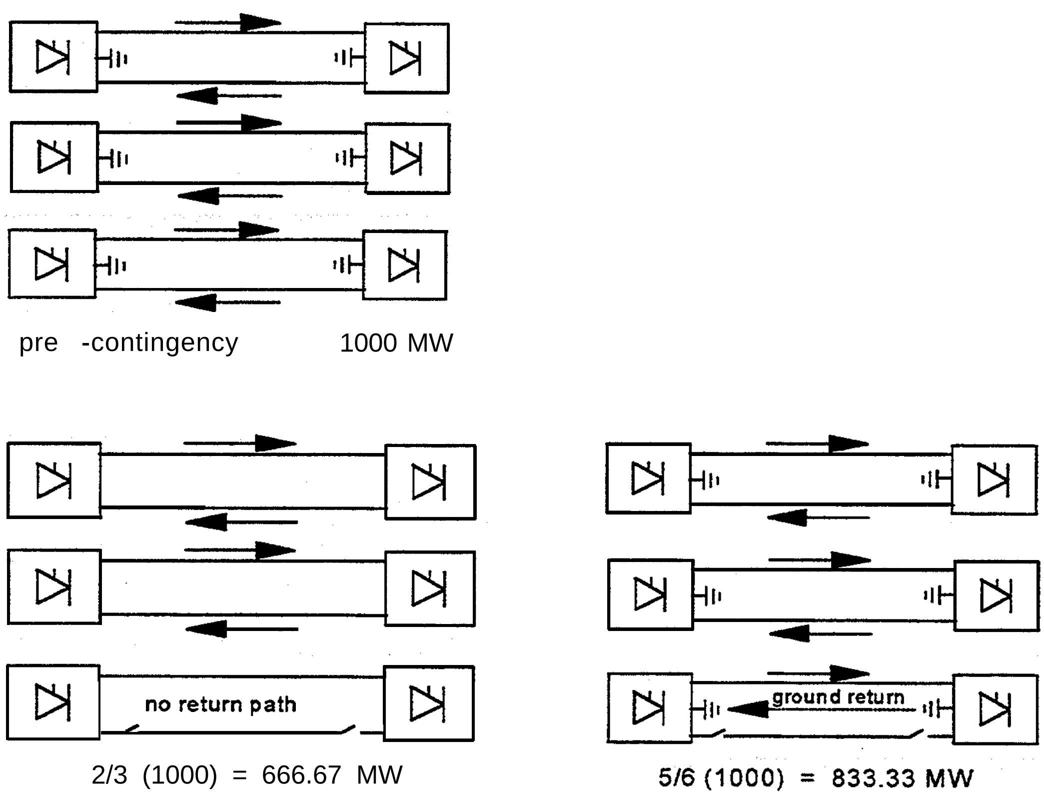
If a spare conductor is provided with switching to connect it in place of a faulted pole then the break-even distance is as noted in the table below. At distances where HVDC becomes competitive with ac, it appears that the extra cost of a spare pole might be justified when the cost of peaking capacity is considered.

Capacity cost $/KW	Break-even Distance *
0	180
100	160
200	110
300	50

* Comparing full cost HVDC *with* spare *pole* to *cost* of double circuit 230 kV line.

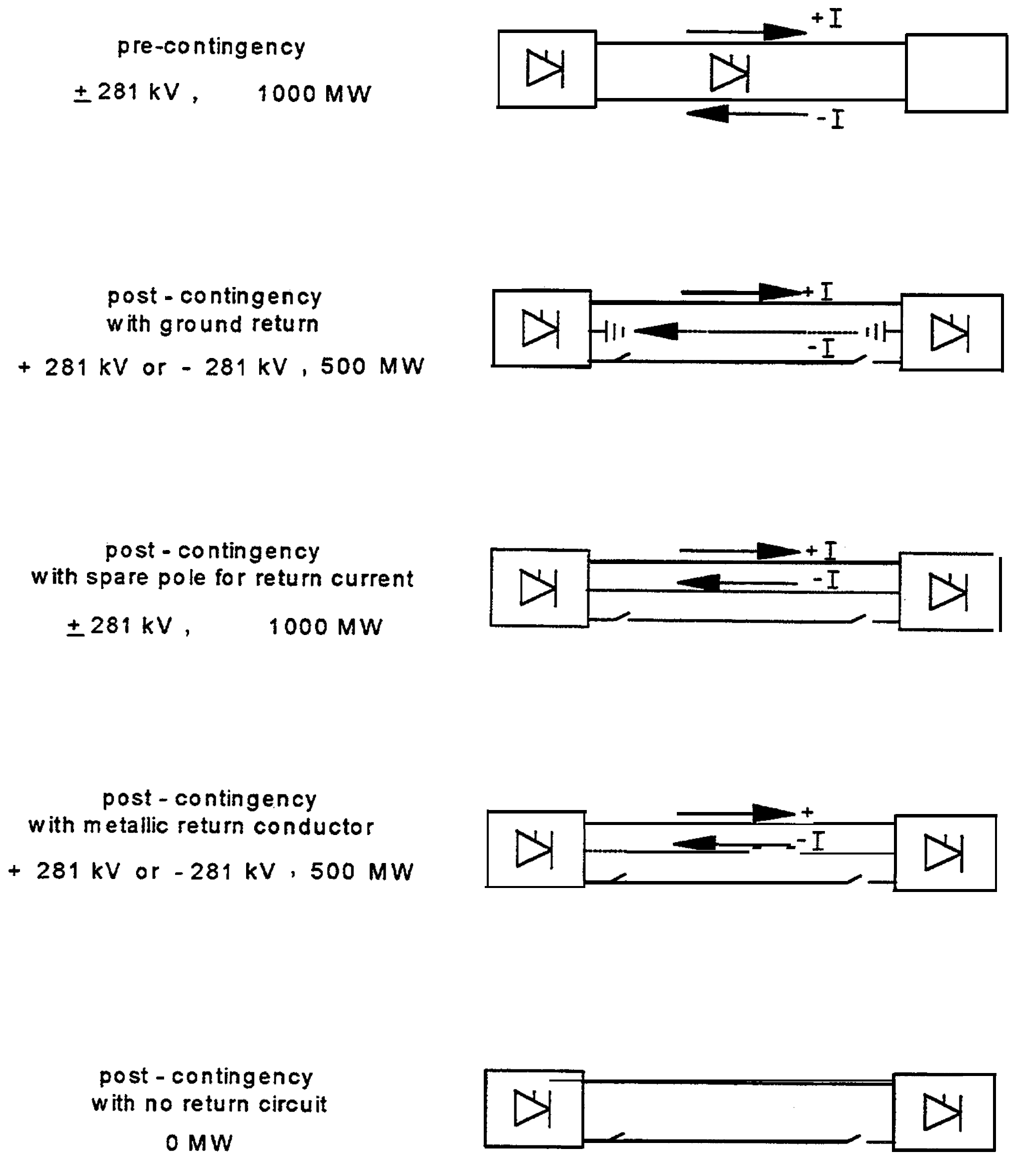


a) HVDC Configurations in Case 8



b) HVDC Configurations in Case 9

Figure 6.7 - HVDC configurations competing with ac alternatives



c) HVDC Configurations for Case 10

Figure 6.7 - HVDC configurations competing with ac alternatives- CONTINUED

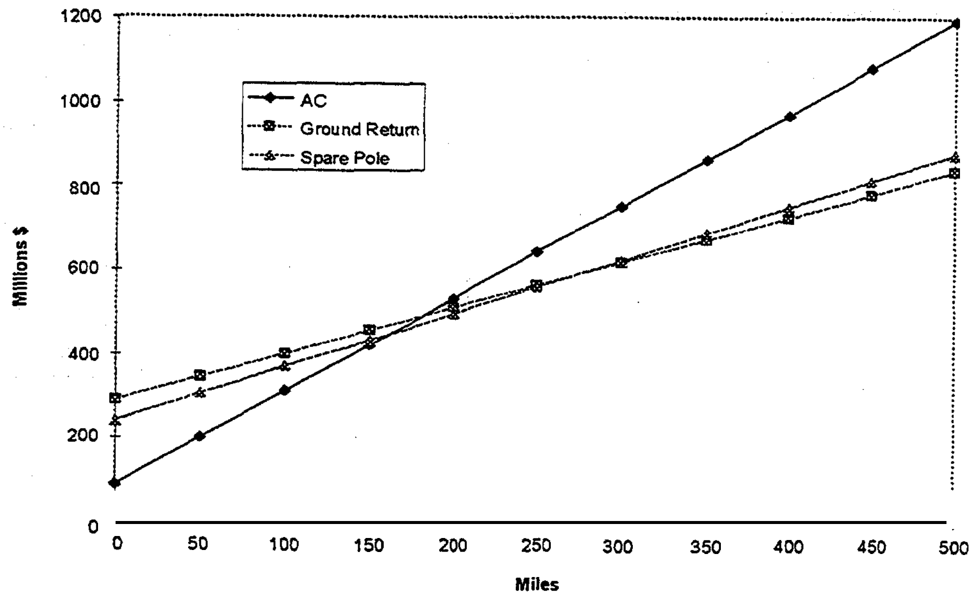


Figure 6.8 - Cost vs. length for double circuit 230 kV ac line and ±281 kV bipole; converter priced at today's cost ($100/kW/terminal). Line, station and var compensation and losses for 1000 MW max. load. *Peaking capacity priced at $100 / kW.*

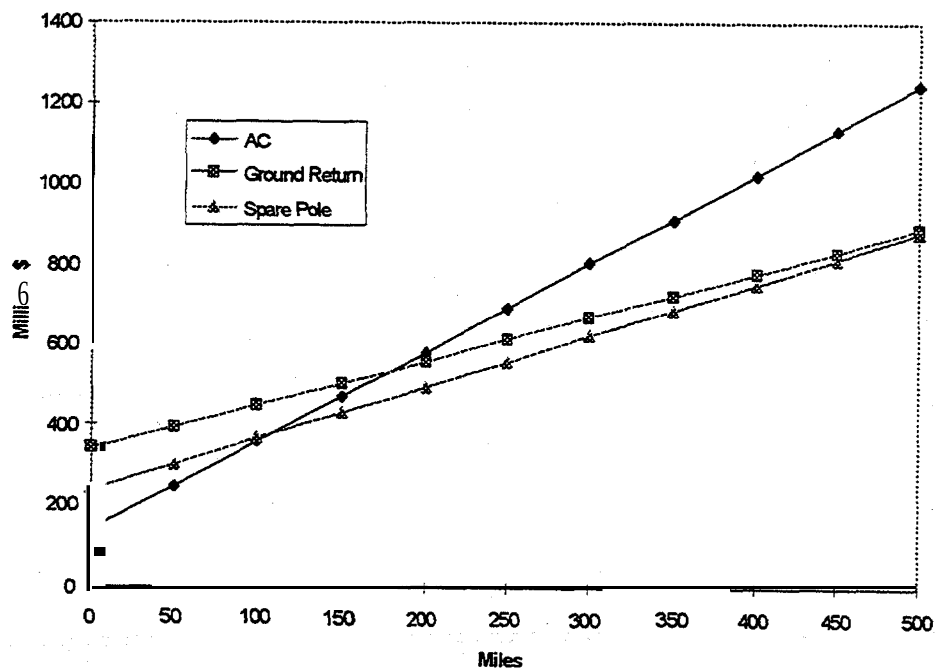


Figure *6.9 - Same* as Figure 6.8 except *peaking capacity priced at $200 / kW.*

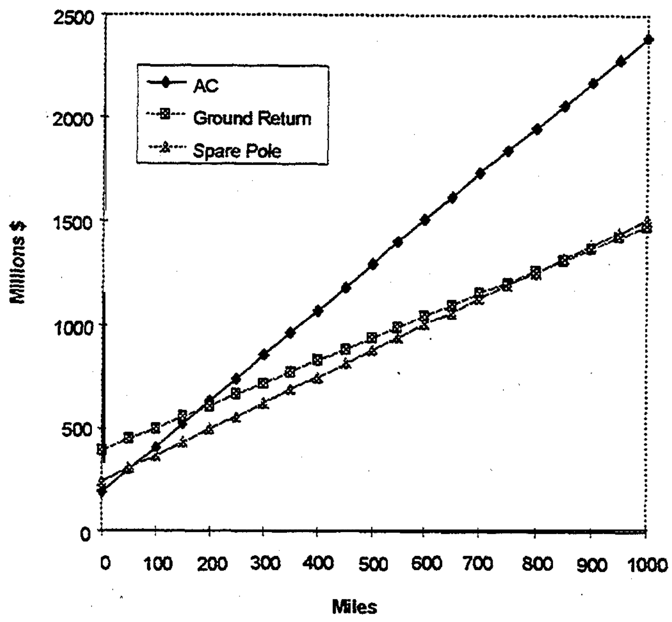


Figure 6.10 - Same as Figure 6.8 except *peaking capacitypriced at $300 / kW*

Case 9: Double Circuit 230 kV AC vs. Three ±188 kV DC Bipoles

A double circuit AC line could be *converted* into transmission circuits for 3 DC bipoles. Aside from the added converters, this may only require changing the insulators. The conversion might also be done while still operating with ac so the down time could be minimal.

For this case a double circuit 230 kV ac line (188 kV peak line to ground, 1000 MW thermal capacity) is compared to 3-l 88 kV HVDC bipoles. This conversion is the same as that considered in Case 5 of Section 6.2. The salvage value of any ac substation equipment removed to convert to dc is assumed to equal the cost of removal. The three bipoles are assumed to use towers and conductors that were previously used by a double circuit 230 kV line. The total thermal capacity of the lines operated with dc is 14.5 1 MW, a fact that is *not* exploited until later in the analysis. Figures 6.11, 6.12, and 6.13 show the total costs when the most limiting contingency is assumed to be an outage on the line itself. Today's cost of converters (about $100/KW/terminal) was assumed for results in these figures. The cost of the lost transfer capacity for a single circuit outage is included. The needed lost transfer capacity is evaluated as follows:

Figure	Value of Lost Transfer Capacity
6.11	100$/kW
6.12	200$/kW
6.13	300$/kW

Curves for two HVDC options are shown in Figures 6.11, 6.12, and 6.13. The pre-contingency and post-outage capacities are illustrated in Figure 6.7b and are summarized below:

Transmission Configuration	Combined Capacity of all Lines/terminals Before Outage	Combined Capacity of all Remaining Lines/terminals After Outage of Ckt or Pole
Double Ckt 230 kV ac Line	1000 MW	500 MW
Three ±188 kV Bipoles with no Return Path	1000 MW	666.67 MW
Three ±188 kV Bipoles with Ground Return	1000 MW	833.33 MW

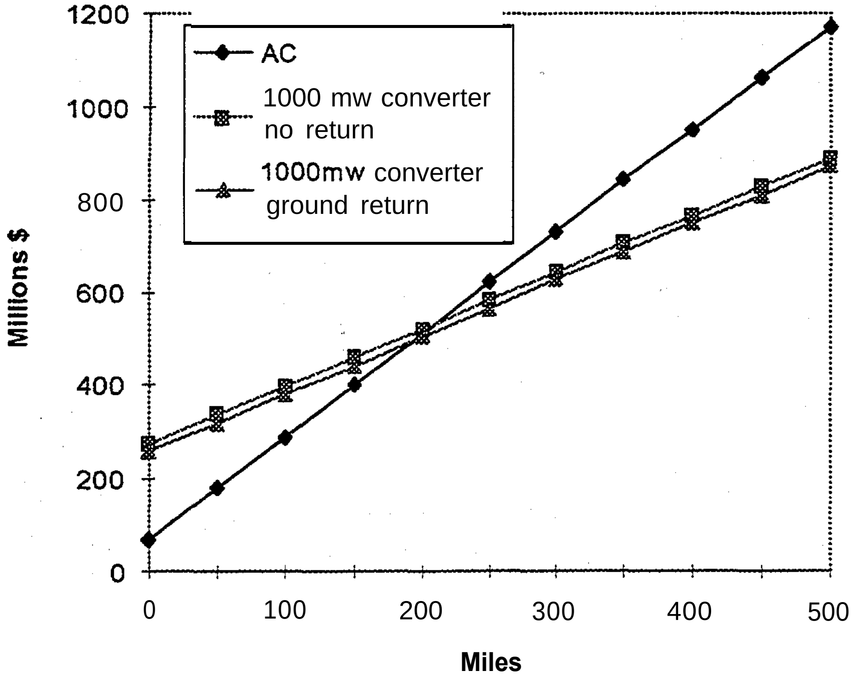


Figure 6.11 - Cost vs. length for double circuit 230 kV ac line and three ±188 kV bipoles derived by converting the double circuit 230 kV line and adding converters totaling 1000 MW capacity. Converters costed at $100/kW/terminal. Ratings of lines, substations, var compensation and *losses* for 1000 MW. *Peaking capacity valued at $100/ kW.*

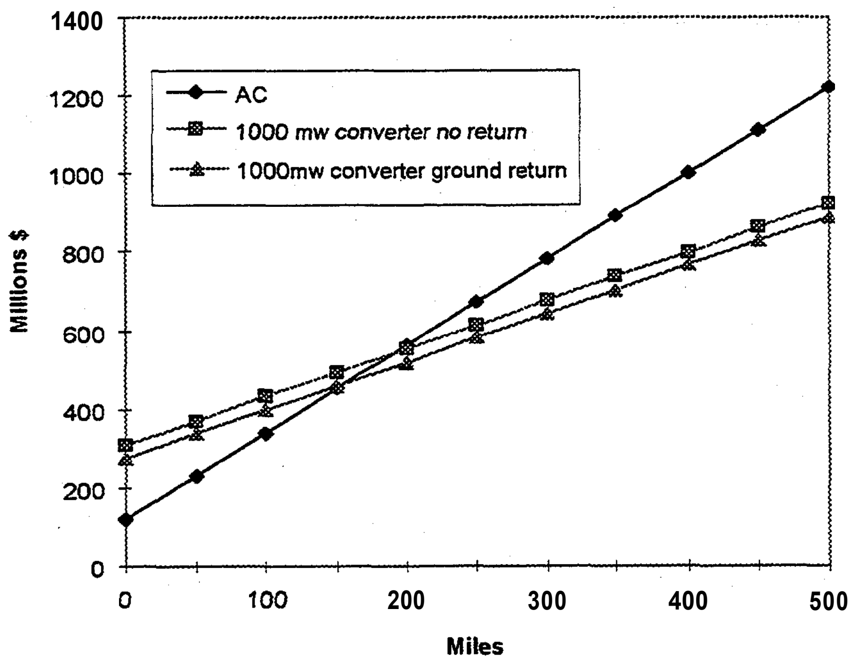


Figure 6.12 - *Same* as Figure *6.11* except *peaking capacity valued at $200/kW.*

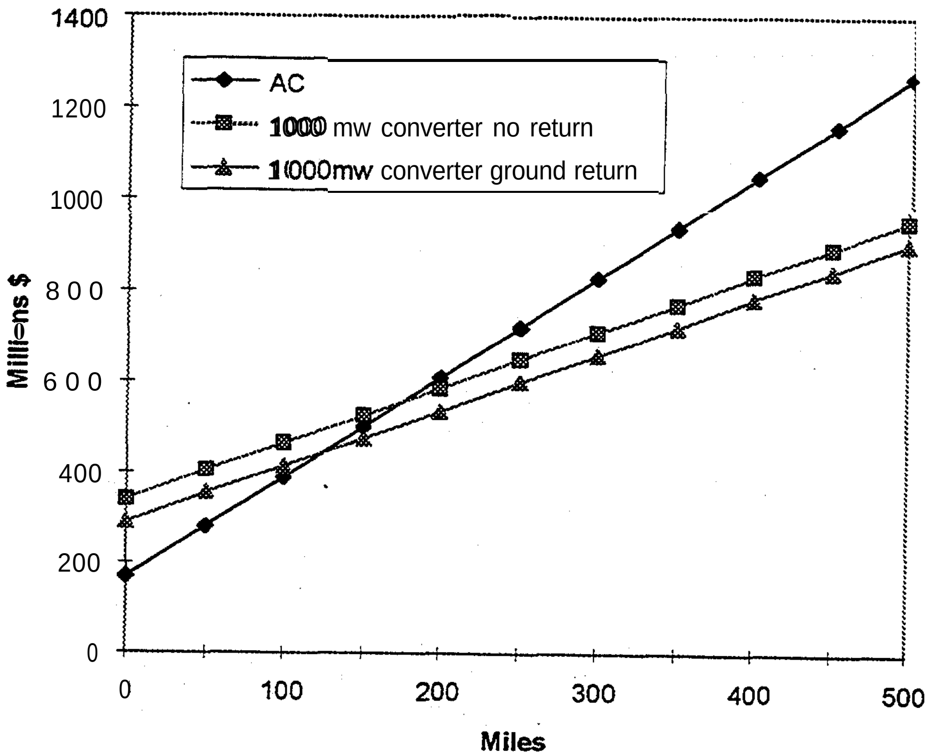


Figure 6.13 - Same as Figure 6.11 except *peaking capacity valued at $300/kW.*

Break-even Distance, Comparisons. Figure 6.14 shows for several values of lost transfer capacity how the break-even distance varies with converter cost. There are curves for an HVDC system with ground return as well as curves for a system with no ground return. Ground return is the most economic HVDC option in all cases. The abscissa of this figure indicates per unit converter cost, where one p.u. corresponds to today's normal converter costs; approximately 100 $/kW/converter. Ignoring the value of transfer capability lost during an outage, the break-even distance with present converter costs is 226 miles. This is the same as the break-even distance given in figure 6.3 in Section 6.2.

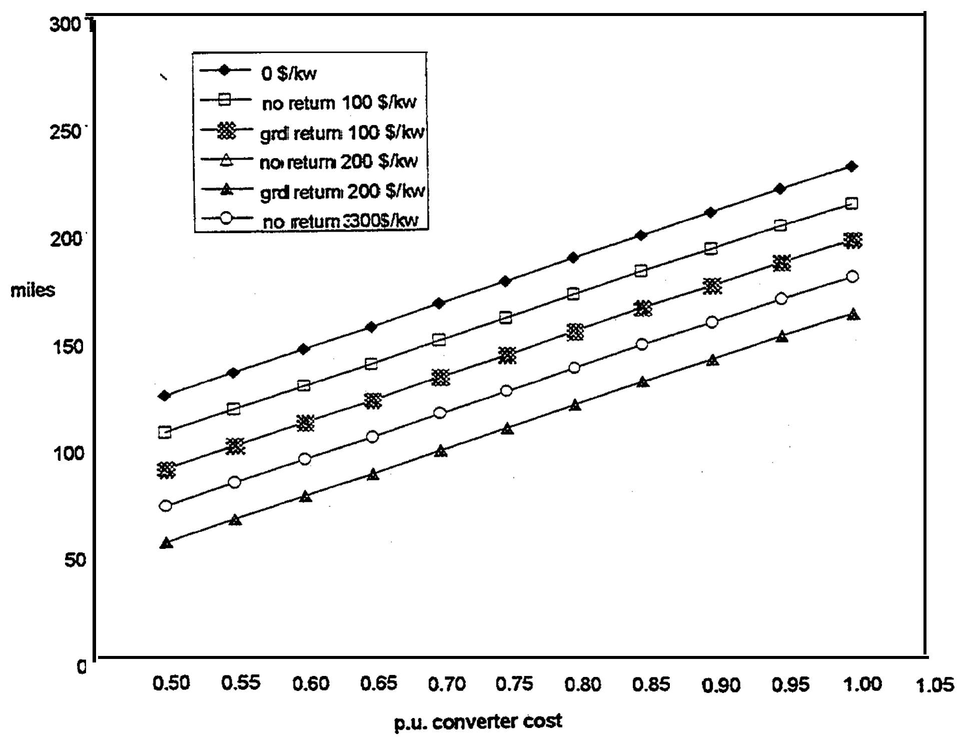


Figure 6.14 -Break-even distance between 2-230 kV ac and conversion of same to three ±188kV bipoles, converters and lines rated for 1000 MW and loaded same. Peaking capacity for first contingency outage valued at $/kW in legend.

Tabulating the break even distances for 1 p.u. converter costs ($100/KW/term.) yields:

$/KW	Ground Return	No Return
0	226 mi.	226 mi.
100	192 mi.	209 mi.
200	158 mi.	192 mi.
300	124 mi.	175 mi.

V&e of Reserve on HVDC. Less peaking (generation) capacity may be required in the load area if suitable transmission capacity is held in reserve to cover line or local generation outages. The double circuit ac line in this example is assumed to be loaded to its thermal capacity in the normal pre-contingency state so it cannot provide any reserve. The ac - to - dc conversion in this case provides for 145 1 MW of line capacity an increase over the 1000 MW capacity when operated ac. This 451 MW advantage could provide reserve capacity, provided the extra capacity is also available in the HVDC converters. That is, the three ±188 kV bipoles that result from converting a double circuit 230 kV ac line (see Figure 6.1e) must be equipped with higher-rated converters such that their combined capacity matches the line's capacity of 145 1 MW. The extra capacity (over 1000 MW of the competing double circuit ac line) is deployed only for contingency conditions. This reserve capacity in the HVDC option could be deployed in two ways.

1. If the critical contingency involves one of the poles of the line in question, then the remaining pole could utilize some of its reserve capacity to reduce the amount of peaking generation or parallel system reserve necessary to cover the load. This scenario was not studied.

2. If the critical contingency does <u>not</u> involve the line itself -- the intact HVDC line could employ surplus transfer capacity where-as the ac option could not since it is at thermal loading to begin with. This scenario was studied and the results are discussed next.

Figure 6.15 compares the ac and HVDC options in terms of the break-even distance if the outage of some other system component (a branch in the "parallel path" system or local generation) is the most limiting contingency. Here the dc option is credited for replacing lost transfer capacity up to 451 MW; the difference between the normal maximum loading (1000 MW) and the thermal capability (145 1 MW) of the dc line.

This becomes economical if transfer capacity during a single contingency is worth more than the cost of the converters. This is evident from close study of Figure 6.15. That figure contains six curves for a 145 1 MW converter, each of which is based on a different value for the surplus transfer capacity. The figure also contains one curve for a 1000 MW converter which of course has no surplus capacity. The 1000 MW curve intersects the 1451 MW curve associated with $200/kW cost of surplus capacity at one per unit converter cost. Recalling that a converter cost of 1 p.u. corresponds to today's normal converter costs (approximately 100 $/kW/converter) then two terminals account for $200/kW, equal to the cost of reserve capacity.

The curves suggest that, at today's HVDC converter cost (100 $/kW/converter), overrated converters can be economical if lost transfer capacity is valued at more than 200 $/kW. Figure 6.15 also shows that the break-even distance is reduced significantly when this is the case. Lower converter cost would of course make it economical to use overrated converters when the price for lost transfer capability is lower. For instance, if converter costs were 50% of today's cost, overrated terminals could be justified if replacement capacity costs are greater than only $1 00/kW. Viewing it another way, if peak capacity costs are $250/kW, then break-even distance for this ac -vs- dc scenario is only 55 miles.

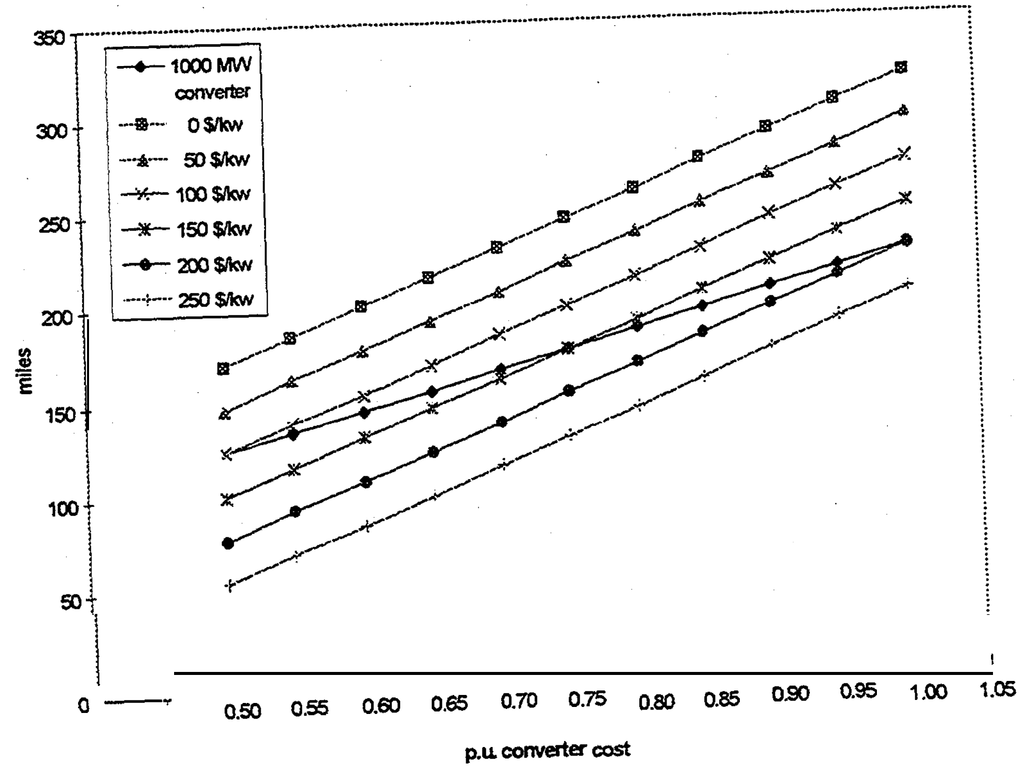


Figure 6.15 - Break-even distance between 2-230 kV ac and conversion of same to three ±188kV bipolar. Outage in parallel path system or loss of generation Peaking, not part of subject line. Peaking capacity for first contingency outage valued at $/kW shown in legend. AC line rated at 1000 MW but HVDC rated at 1451 MW, both operating initially at 1000 MW. For *comparison,* one curve shows HVDC rated at 1000 MW and a capacity value of zero ($0).

Case 10: Single Circuit 345 kV AC vs. a ±281 kV DC Bipole

Figures 6.16, 6.17, and 6.18 show total costs versus distance for a single circuit 345 kV ac line and four variations of a ±281 kV DC bipole. Those variations are illustrated in Figure 6.7c. The comparison between the ac line and the HVDC option with ground return is the same as that considered in Case 2 of Section 6.2. The thermal rating of a 345 kV single circuit AC line is normally around 1000 MVA. The HVDC alternative is chosen to have the same peak voltage as the ac alternative and the conductor sizes are assumed to be the same. The thermal rating for the HVDC bipole circuit is therefore almost the same.

The HVDC option with a spare pole conductor might in fact be the result of converting an existing 345 kV AC line for DC operation. The spare pole is assumed to be fully insulated for operation at 28 1 kV. The configuration "with metallic return" implies the use of a partially insulated return conductor that cannot operate at 281 kV. It is typically rated for the IR voltage drop at normal load current plus the usual switching and lightning surges. However, for simplicity in this analysis, the cost of the metallic return was assumed equal to that of a fully insulated pole conductor. The difference in cost between a fully insulated pole conductor and reduced-insulation metallic return is not trivial but the impact on total system cost is relatively small. The difference in cost of lost transfer capacity is significant so it was not ignored. That is, with metallic return, the capacity after a pole outage is equal to that of ground return case, viz. 500 MW. For the configuration with no return path, of course, loss of a pole leaves zero capacity, the same as loss of the single circuit ac line.

The transmission installed cost and present worth of future losses are summed with the cost of peaking capacity and is plotted on the ordinate. The lost transfer capacity for a single contingency is evaluated as follows:

Figure	Value of Lost Transfer Capacity
6.16	100$/kW
6.17	200$/kW
6.18	300$/kW

As can be seen from these figures, if there is no return path for direct current during an outage, the ac and HVDC cost are equal at 385 miles. The distance at which these costs are equal (break-even distance) does not depend upon the value of lost transfer capacity since neither the ac or HVDC alternative would have transmission capability with a single circuit outage in this case. This is the same as the result in Figure 6.3, Case 2 in Section 6.2.

If lost transfer capacity is valued at 1 00$/kW, the break-even distance for ground return is approximately 300 miles. Ground return is the cheapest alternative (ac or dc) above this distance and ac is the cheapest alternative below 300 miles. If ground return is not feasible, the break-even distance with a spare pole is also 300 miles but this is a more expensive option than ground return for longer distances. The break-even distance for metallic return is shown as approximately 450 miles. If the true (lower) cost of a **partially-**insulated conductor were used, that distance would come down only slightly since the main difference between this configuration and the spare pole is the cost of peaking capacity required.

If lost transfer capacity is valued at more than **200$/kW**, an HVDC line with a spare pole is more economical than the single circuit ac line for all distances. The break-even distance for ground return is approximately 200 miles and it becomes more economical than a spare pole for distances above 550 miles. More importantly, the HVDC option with a spare pole is more cost effective than the single 345 **kV** circuit for nearly all lengths.

If lost transfer capacity were valued at more than **300$/MW**, the break-even distance for an HVDC line with ground return would be approximately 100 miles. The HVDC line with a metallic return is more cost effective than the ac alternative for distances greater than 150 miles. With a spare pole, the **HVDC** is less costly than ac for any length. See table below for a summary.

$/KW	**no return**	**ground return**	**metallic return**	**spare pole**	**Figure**
100	385	285	450	300	6.16
200	385	200	300	0	6.17
300	385	100	150	--	6.18

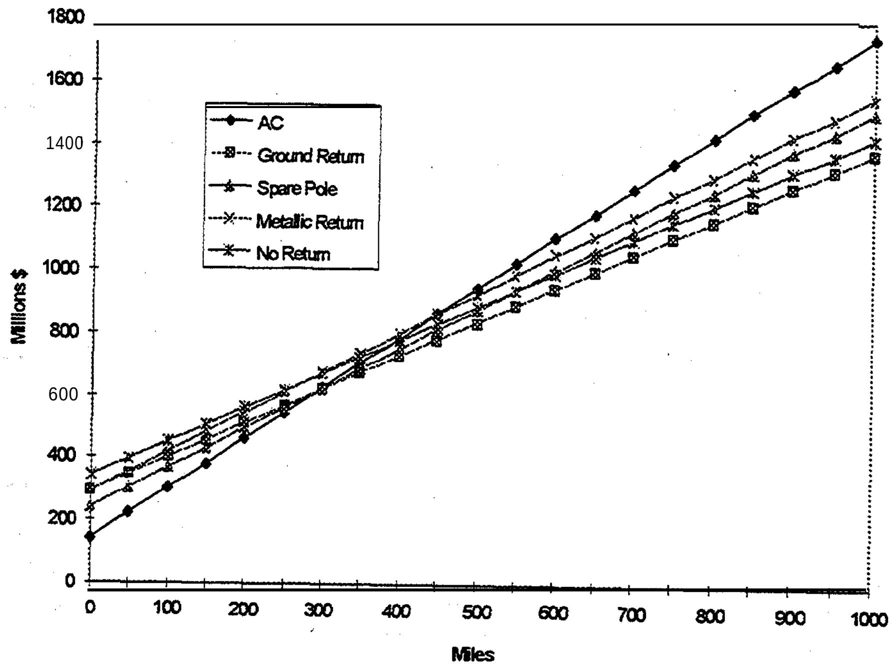


Figure 6.16 - Cost vs. length for single circuit 345 kV *ac* line and ±281 kV bipole. Converters costed at $100/kW/terminal. Ratings of lines, substations, var compensation and losses for 1000 MW. *Peaking capacity valued at $100/kW.*

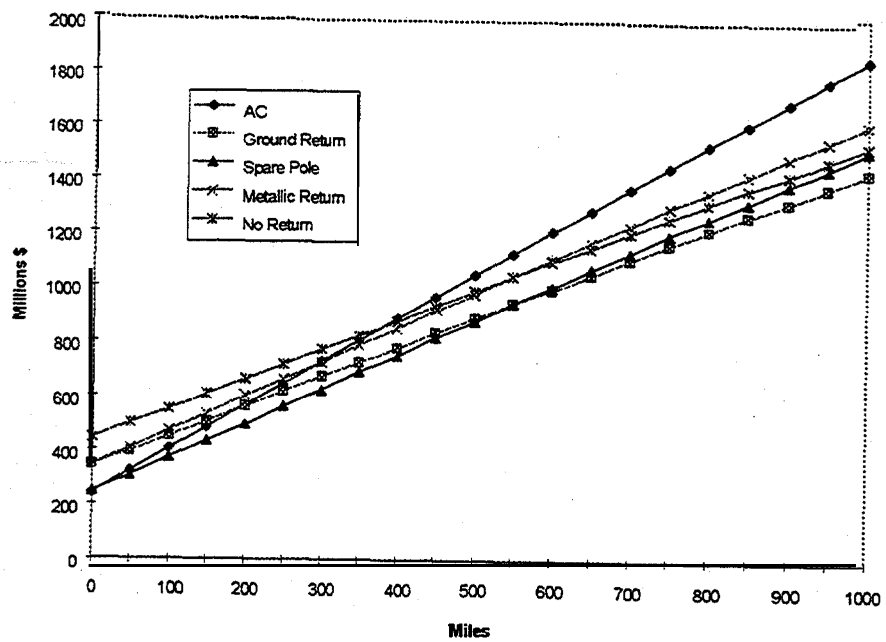


Figure 6.17 - Same as Figure 6.16 except *peaking capacity valued at $200/kW.*

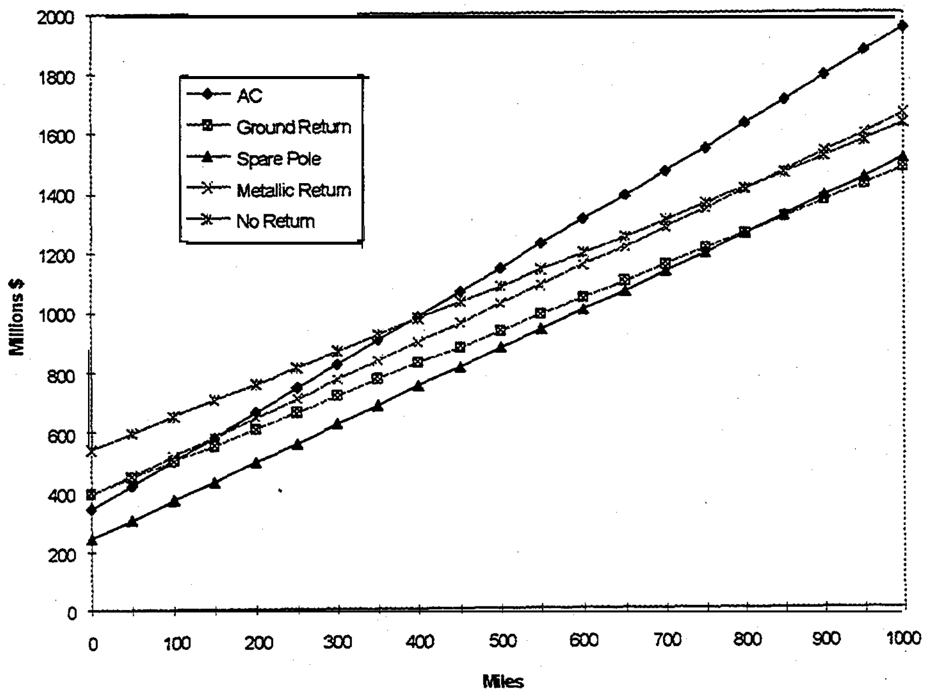


Figure 6.18 - Same as Figure 6.16 except *peaking capacity valued at **$300/kW**.*

6.5 BREAK EVEN DISTANCE VARIES WITH PRESENT WORTH OF LOSSES

The results provided in previous sections assumed that losses were valued at $2,080 per KW. That value was computed using 8% interest over 30 years with a capacity charge of $900/KW and an energy charge of $30 per MW-hr. This section provides results with these values varied such that the effective value of losses ranges from zero to $1,040/KW and $2,080/KW. Both today's heavy loading and loading to thermal limits were considered.

Case I - Single 500 kV ac - vs k-408 kV dc Bipole

The value of losses has a large effect on the break even distance as loading increases. The impact seen in Figure 6.20 (thermal loading) is much greater than at normal heavy load (Fig.6.19).

"Heavy Load" of 1000 MW.

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ KW**	**$2,080/ KW**
0.50	297	279	267
0.75	482	433	399
1.00	**667**	588	531

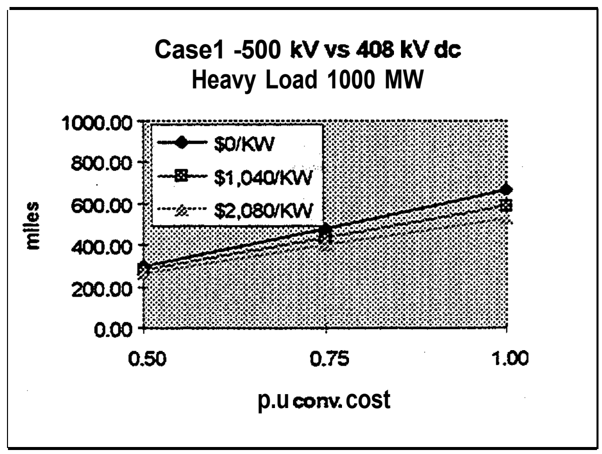


Figure 6.19

Thermal Load of 2000 MW

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ KW**	**$2,080/ KW**
0.50	421	303	248
0.75	684	470	371
1.00	947	638	494

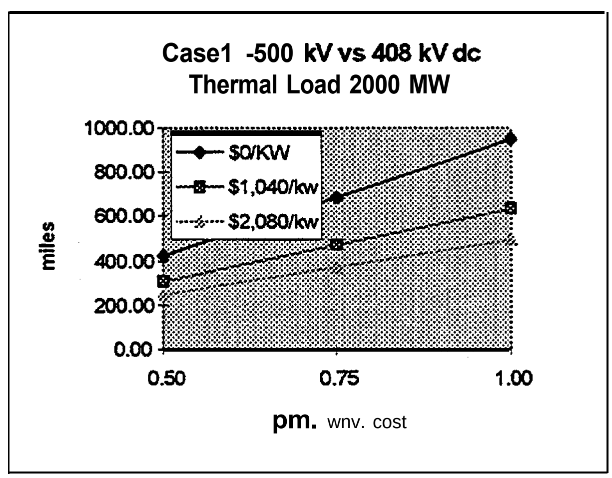


Figure 6.20

Case 2 - Single 345 kV ac - vs - ±281 kV dc Bipole

Figures 6.21 and 6.22 show a similar effect of load and loss value on break even distance for this case as in Case 1 above. At normal ‘heavy load” the value of losses has less impact than if the lines are loaded to thermal limits.

“Heavy Load” of 500 MW

	Break Even Distances for Given Loss Values		
cost Mult.	**$0/KW**	**$1,040/ Kw**	**$2,080/ Kw**
0.50	**213**	**203**	196
0.75	**346**	**315**	**293**
1.00	**479**	**428**	**390**

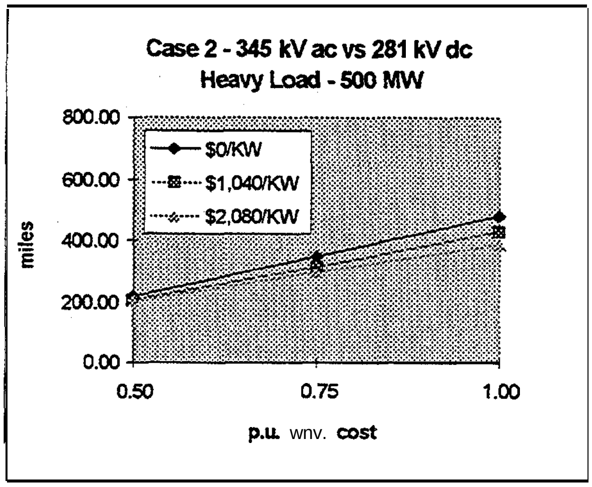


Figure 6.2 1

Thermal Load of 1000 **MW**

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ KW**	**$2,080/ KW**
0.50	**328**	**236**	193
0.75	**532**	**366**	**289**
1.00	**737**	**497**	**385**

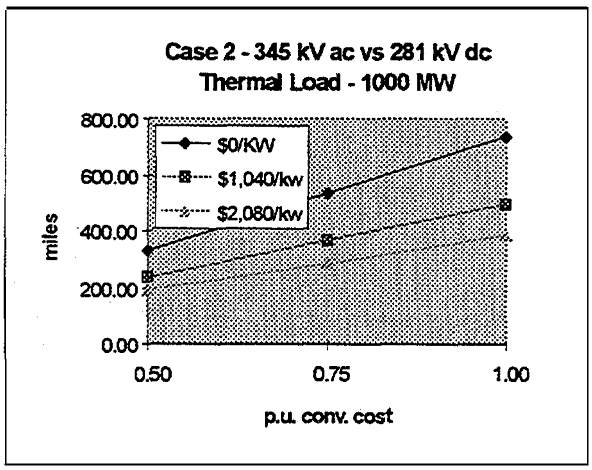


Figure 6.22

Case 3 - Double Circuit 230 kV ac - vs - ±281 kV dc Bipote

As seen in Figures 6.23 and 6.24 the relative effect of the cost of losses is similar for both load levels considered. A low value for losses provides a large advantage to the ac option. However, as loading approaches thermal levels, and the cost of losses is high ($2,080/KW) there appears a nearly a two-to-one advantage to the dc alternative.

"Heavy Load" of 500 MW

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ Kw**	**$2,080/ KW**
0.50	573	238	163
0.75	931	370	243
1.00	*1290*	502	324

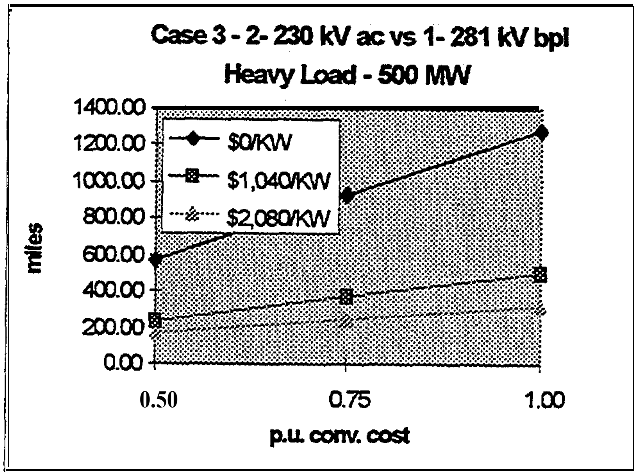


Figure 6.23

Thermal Load of 1000 MW

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ KW**	**$2,080/ KW**
0.50	515	142	90
0.75	837	221	135
1.00	1159	300	180

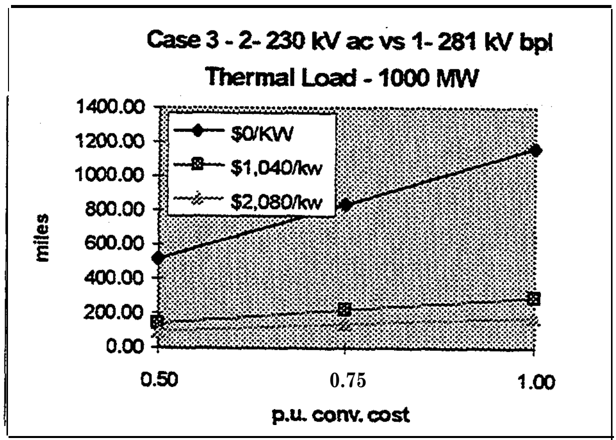


Figure 6.24

Case 4 - Single Circuit 345 kV ac - vs - ±408 kV dc Bipole

This case is very similar to Case 2 where a 345 kV line is compared with a ±281 kV bipole. An increase in the value of losses favors the dc option especially at higher line loadings. However, if losses cost very little, the ac option with reactive compensation supplied to accomodate loadings approaching thermal limits is more cost effective by a large margin.

'Heavy Load" of 500 MW

	Break Even Distances for Given Loss Values		
cost Mult.	**$0/KW**	**$1,040/ Kw**	**$2,080/ Kw**
0.50	178	162	151
0.75	289	251	225
1.00	**400**	340	300

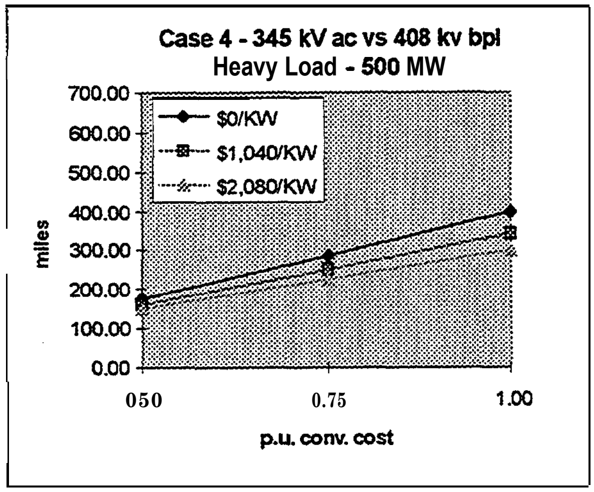


Figure 6.25

Thermal Load of 1000 MW

	Break Even Distances for Given Loss Values		
cost Mult.	**$0/KW**	**$1,040/ Kw**	**$2,080/ Kw**
0.50	284	181	140
0.75	462	281	**280**
1.00	**639**	**381**	**279**

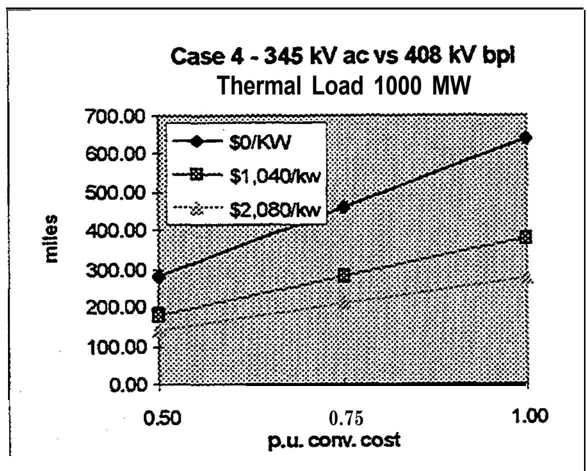


Figure 6.26

Case 5 - Double Circuit 230 kV ac - vs - Conversion of same to 3 - ±188 kV dc Bipoles

As seen in Figure 6.27, with losses costing nothing and operating at today's normal "heavy" load, there is no incentive to convert the double circuit 230 kV line to dc operation. However, increased loading approaching thermal limits causes a dramatic reduction in the break even distance (Figure 6.28) in favor of conversion to dc. This is especially true if the cost of losses are high as seen in both figures.

"Heavy" Load of 500 MW

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ KW**	**$2,080/ KW**
0.50	2507	429	255
0.75	3761	623	360
1.00	5015	818	465

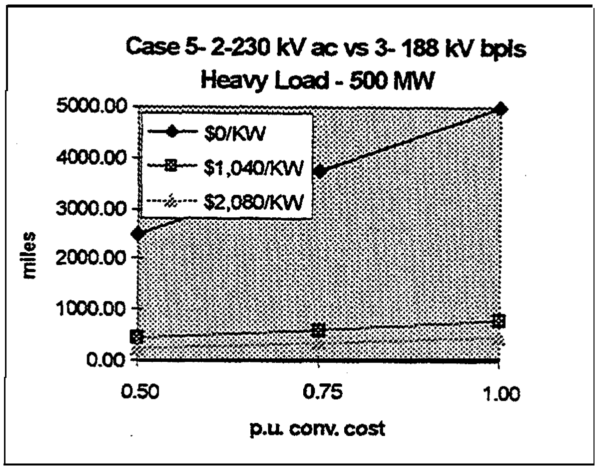


Figure 6.27

Thermal Load of 1000 MW

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ KW**	**$2,080/ KW**
0.50	948	204	124
0.75	1423	297	175
1.00	1897	389	226

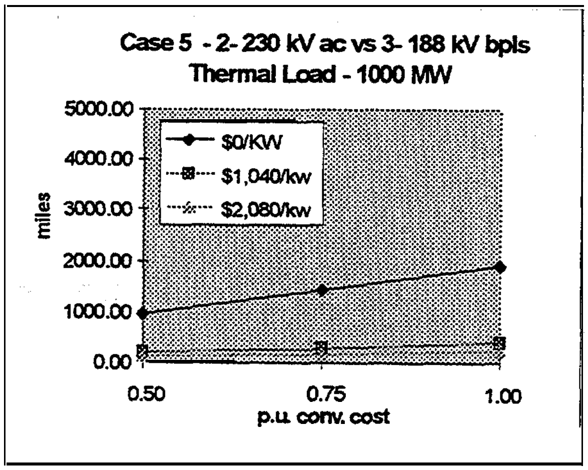


Figure 6.28

Case 6 - Add 3rd 230 kV ac or Convert Double Circuit 230 kV ac to 3 - ±188 kv Bipoles

Comparing Figures 6.29 and 6.30 shows that line loading has only a modest impact on the choice in this scenario. The cost of losses does make a difference at all loading levels. The break even distance with a high loss penalty ($2,080/KW) is reduced by about half of the break even distance when losses involve no cost.

"Heavy" Load of 1000 MW

	Break Even Distances for Given Loss Values		
Cost Mult.	**$0/KW**	**$1,040/ Kw**	**$2,080/ Kw**
0.50	339	239	193
0.75	520	354	277
1.00	702	469	361

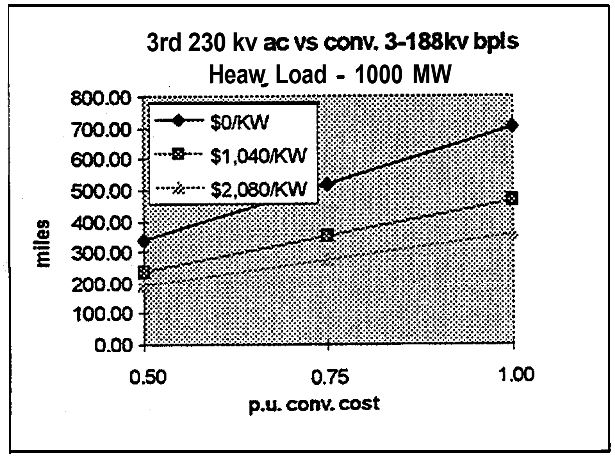


Figure 6.29

Thermal Load of 1500 MW

	Break Even Distances for Given Loss Values		
cost Mult.	**$0/KW**	**$1,040/ Kw**	**$2,080/ Kw**
0.50	335	200	151
0.75	514	298	217
1.00	694	394	284

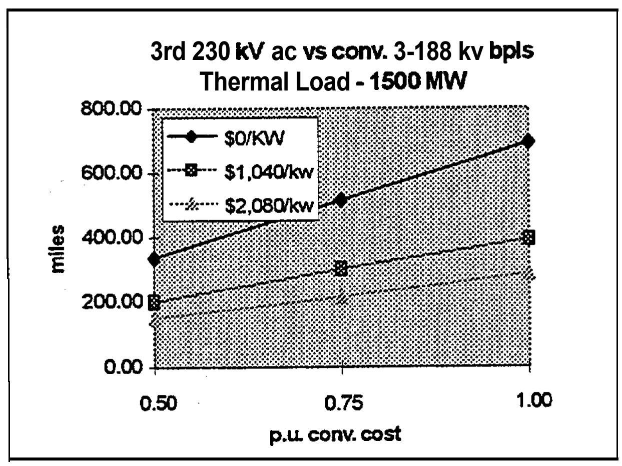


Figure 6.30

6.6 SUMMARY

Subject to a number of economic factors, HVDC can be competitive with an ac alternatives. Each transmission project must be evaluated as a unique situation. The seven representative economic scenarios studied in this section provide some limited guidance for when HVDC might be economically preferred over ac. Clearly, reduced costs for converters is very important if transmission providers are to exploit the technical benefits of dc. The present worth of losses has an effect, and can become very important as line loadings rise closer to the thermal limits. This is pronounced in the lower voltage (230 kV) line examples. Provided the reliability criteria involved treats a bipolar HVDC line as two circuits, then dc can be more economical than a single circuit ac line that must supply capacity as well as energy. In some cases studied with high capacity value ($200/KW and up), building the dc line with three pole conductors can be-more economical than single circuit ac line for any distance. The examples in this section provide food-for-thought for future transmission developer/owners.

7. CABLE APPLICATIONS

Underground and submarine cable technology has evolved considerably since it's beginnings in nineteenth century Europe. It's earliest applications were for telegraph with underground (direct current) streetlighting as the first power application in the U.S. Since then applications up to 500 kV have been commisioned with selfcontained liquid and gas-filled cables. However, high-pressure-fluid-filled (HPFF) pipe-type cables up to 345 kV have become a U.S. "standard" for underground and short submarine cables. Extruded-dielectric cables, including the XLPE (cross-linked polyethylne) type, are gaining popularity for their compactness and low maintenance. They also have lower losses and require less charging current than most other types. Japan with its enormous power densities, are investing heavily in the development and application of 500 kV XLPE cables. However, the commercially-available extruded cables are unsuitable for high voltage dc at this time as noted later in Section 7.1.1.

Beyond a certain length, which varies with applied voltage, ac cables become impractical due to their capacitive charging current. At a so-called "critical-1ength"for a given cable type and ac voltage, the charging current equals the thermal limit of the cable so there is no room for active power. Figure 7.1 illustrates this effect for a specific type of 345 kV cable; this type is used as an example in Section 7.2.

Table 7.1 lists the thermal capacity, critical length and a more realistic maximum length as a function of voltage for a different size / type cable than represented in Figure 7.1. The "realistic" maximum length is that length for which the capacity for active power is at 80% of the thermal capacity. [EPRI, 1991] .

Whenever possible, shunt reactors are used at strategic intermediate points along underground cables to deal with the charging current; a practice that is not yet practical for submarine cables. Therefore, transmitting large amounts of power over substantial distances with today's technology requires dc cables. The choice is system specific, and economic drivers prevail as always.

The remainder of this section, summarizes the state of the technology and the relative economics of ac verus dc in terms of a specific example. The example deals with transmitting either 500 MW or 1000 Mw over two under-water (in a river-bed, e.g.) distances: 30 km and 100 km. Section 7.1 summarizes the state of the technology available and Section 7.2 contains a compartive design/costing study exercise for both ac and dc approaches. Appendix 5 includes some perspectives on manufacturing, transporting and installing the cables covered in the example.

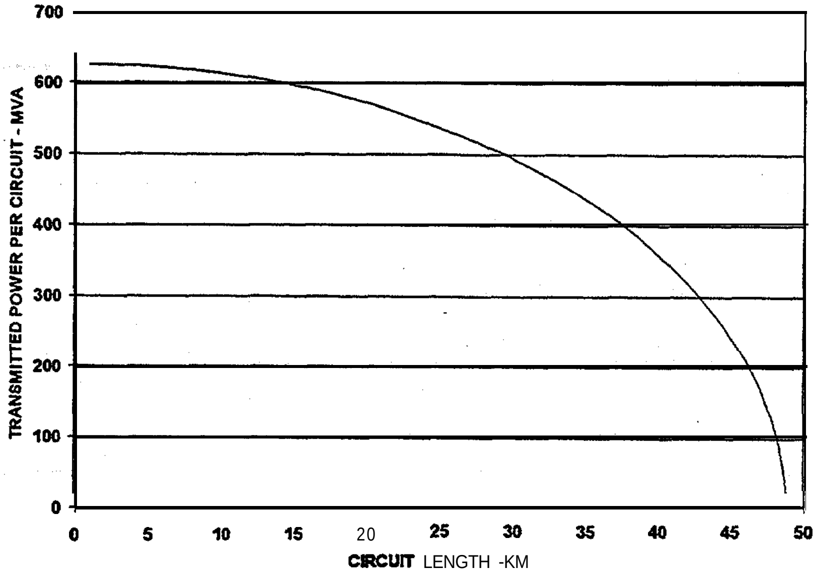


FIGURE 7.1: TRANSMITTABLE POWER AS A FUNCTION OF CIRCUIT LENGTH IN THE CASE OF THE 345 kVAC SUBMARINE CABLE STUDIED IN SECTION 7.2 OF THIS REPORT

TABLE 7.1: APPROXIMATE MVA AND DISTANCE LIMITS FOR UNCOMPENSATED UG OR SUBMARINE CABLES OF TYPE DESCRIBED BELOW * (Derived from Figure 10.8 in "Underground Transmission Systems" - Reference Book, 1992 Edition, EPRI Report TR-101670, Project 7909-01)

*This data holds for a 2000 kcmil copper conductor, impregnated-paper-insulated HPFF pipe-type cable with a loss factor of 1.0 (loaded to thermal continuously) and a earth thermal resistivity of 90C°-cm / Watt (typical with fluidized back fill and low moisture content)

Cable Voltage kV (ac)	Thermal Capacity (MVA)	Critical Length (km)	Realistic Loading (80% of Thermal) & Maximum Length	
	approx.	approx.	Capacity (MVA)	Length (km)
138	210	72	190	38
230	350	63	300	32
345	480	44	410	23
500	560	28	480	13

Summary of Example Studied

The transmission of 500 MW (MVA) of electrical power, for the distances specified, in a river-bed environment using high voltage ac or dc submarine power transmission cables is technically feasible and well within the existing state-of-the-art. The results of a specific comparison/design exercise given in Section 7.2 are shown in Table 7.2. Detailed high voltage ac and HVDC cable designs suitable for this purpose have been developed using accepted industry design practice for the cable, typical thermal parameters for the river-bed environment, and an appropriate installation configuration.

In the case of dc transmission a single cable operating at direct voltage of 400 kV and a ground return conductor will transmit 500 MW over a distance of 100 km with system losses of only 4.0 MW or 0.8 %. Bipolar dc transmission using two cables operating at ±400 kV with no separate return conductor will transmit 1000 MW over a distance of 100 km with system losses of 4 MW.

The installed cost for a 500 MW monopolar 100 km HVDC cable system (excluding converters) is approximately $US 78.3 million. This cost can be reduced by approximately $US 10 to 12 million if the location permits a ground return path, i.e. ground electrodes, in place of a return conductor. The costs for a 500 MW, 30 km monopolar HVDC system would be $US 23.5 million. For a 1000 MW, 30 km bipolar system with a return conductor, the cost would be $US 42.5 million. With no separate return conductor it would be $US 38 million.

The installed cost of a 30 km (500 MW) high voltage ac cable installation is about $US 43 million.

Losses for a 30 km monopolar HVDC line with a metalic return would be 1.2 MWs. The losses for a 30 km bipolar HVDC line would also be 1.2 MW.

Long distance AC power transmission is limited by the capacitance charging current and its negative impact on the power cable rating. The cable design analyzed is suitable to transmit 625 MVA per 3-phase cable circuit over distances of a few km at a system voltage of 345 kV. With increasing transmission distance the transmittable power decreases to 500 MW at 30 km and eventually to zero at 49 km (see Figure 7.1). This behaviour is typical of ac transmission by cable (see Table 7.1) and not a feature of the particular cable design under consideration. In fact, the capacitance charging current problem explains why there are no high voltage ac cable circuits longer than a few tens of km.

AC system losses are much more significant than in the corresponding HVDC scenario. In the present example the system losses amount to approximately 5.0 MW or 1 % for the 30 km route length.

TABLE 7.2: SUMMARY OF RESULTS OF EXAMPLE IN SECTION 7.2
COSTS OF AC AND DC OPTIONS FOR 500 MW AND 1000 MW
SUB- CABLES OF 30 KM AND 100 KM LENGTHS

	HVDC						AC	
Rated Voltage (kV)	400						345	
Configuration	Monopole Metalic Return		Bipole No Seperate Return		Bipole Separate Return		1 Three Phase	2 Three Phase
Power (MW)	500		1000		1000		500	1000
Distance (km)	100	30	100	30	100	30	30	30
Installed cost (millions-$) .	78.3	23.5	126.7	38.0	141.6	42.5	43	86
Losses (MW)	4	1.2	4	1.2	4	1.2	5	10

7.1 THE STATE OF THE ART IN SUBMARINE POWER TRANSMISSION

7.1.1 The HVDC Option

Of the four types of power cable which can be considered as being suitable for long distance submarine applications, namely :

- extruded polymeric (e.g. cross-linked polyethylene) insulated cables (extruded cables)

- low-pressure self-contained, oil-filled, paper-tape-insulated cables (SCFF cables)

- gas - pressurised, paper - tape insulated cables (SCGP cables)

Mass - impregnated, non-pressure-assisted, paper-tape-insulated cables (MI cables) the first three can be eliminated from further consideration for the present study for the following reasons :

- Extruded cables are known to be unsuitable for HVDC applications since the very high electrical resistivity of the insulation leads to space charge distortion of the electrical stress and hence an unpredictable breakdown behaviour under superposed direct voltage and voltage surge conditions.

- Of the pressure assisted types the SCFF cable is unsuitable for cable routes in excess of a few tens of kilometers due to the inability of the land-based pumping stations to control the transient pressures created by the oil expansions and contractions which accompany cable load variations. Thus a long submarine cable of this type would fail either due to rupture of the sheath by a high oil pressure during heating or by ionization due to the loss of adequate pressurization during cooling.

- An SCGP cable should perform satisfactorily since there is no diiculty with maintaining gas pressure in long cable links and in principle. However, this cable type had only been used in one cable link, the "Cook Strait 1" HVDC cable link in New Zealand, which was installed in 1964 and which consists of three cables each 39 km in length, operating at 250 kV and transmitting a total of 900 MW. Consequently, service experience with this cable type is very limited.

On the other hand there is a very considerable experience with the MI cable as may be seen from Table 7.3, which summarises the characteristics of the principal HVDC submarine cable links in service at the present time.

TABLE 7.3: THE MAJORITY OF INSTALLED HVDC SUBMARINE CABLE LINKS ARE OF THE MI CABLE TYPE

NAME OF LINK	DATE	VOLTAGE (kV)	POWER (MW)	LENGTH (km)	CABLE TYPE
Gotland 1	1954	100	20	100	MI
Cross Channel 1	1961	100	80	2x52	MI
SAC01	1965	200	100	2x118	MI
Cook Strait 1	1965	250	300	3x39	PIGF
Konti-Skan 1	1965	285	300	64	MI
Vancouver 1	1969	300	156	3x27	MI
Mallorca/Menorca	1972	200	100	4x44	SCFF
Skaggerak 1,2	1976	263	250	2x125	MI
Vancouver 2	1976	300	185	2x35	MI
Hokkaido/Honshu	1980	250	150	2x42	SCFF
Gotland 2,3	1983	150	160	2x100	MI
Cross-Channel 2	1986	270	250	8x50	MI
Konti-Skan 2,3	1988	285	300	2x64	MI
Fenno-Skan	1989	400	500	200	MI
Cook Strait 2	1991	350	500	3x40	MI
Skagerrak 3	1993	350	500	125	MI
Cheju (Korea)	1993	180	150	2x96	MI
Baltic	1994	450	600	250	MI

The cross section of a typical HVDC mass-impregnated cable is shown in Figure 7.2 and the various constructional elements will now be briefly described viz.,

Conductor: The conductor is made of high conductivity copper and consists of a number of annular layers of "conci" or keystone segments laid up around a central copper rod. Each layer is applied with a helical lay opposite to that of the underlying layer to improve torsional stability.

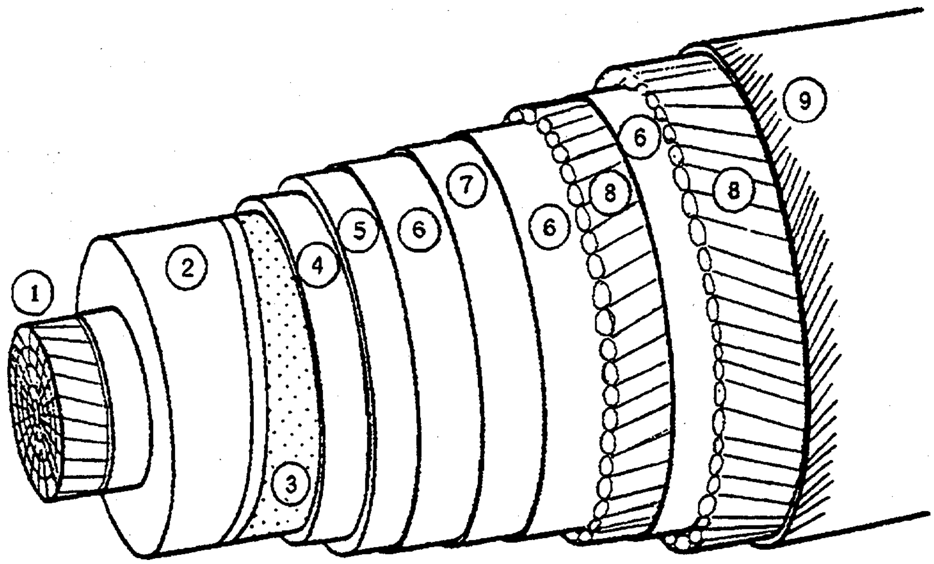


FIGURE 7.2: A TYPICAL MASS-IMPREGNATED HVDC SUBMARINE CABLE

1. **Conductor**
2. **Insulation**
3. **Insulation Screen**
4. **Lead Sheath**
5. **Polyethylene Sheath**
6. **Bedding layer**
7. **Steel Tape**
8. **Armor Wres**
9. **Polypropylene Serving**

Conductor Screen: Despite the smooth surface achievable with solid conci conductors, an electrostatic screen or shield, generally consisting of two or more layers of semiconducting carbon black paper tapes and having a total thickness of approximately 0.5 mm, is applied to ensure optimal electric stress conditions at the conductor/insulation interface.

Insulation: The paper tape insulation used in HVDC cables is manufactured from wood pulp which is washed with deionized water during the paper manufacturing process to reduce it's metallic ion content and hence ionic conductivity. This procedure is considered necessary in order to reduce the risk of electrochemical deterioration which had been observed with certain types of cellulosic materials under direct voltage conditions. Paper tape thicknesses between 90 and 110 microns are generally used with the thinner papers being applied at the inner and outer layers of the insulation. Optimum performance of MT cable insulation requires the use of an impregnant which should be fluid enough at processing temperatures (130 deg C) to permit complete impregnation of the paper insulation in a reasonable time and which must be viscous enough at working temperature to prevent drainage. At the present state-of-the-art an ideal compound has not yet been developed and the best available compound severely restricts the operating temperature (at present to a maximum of 50 °C) and hence the power transmission capacity of MI cables.

Insulation Screen : Like the conductor screen the function of the insulation screen is to provide electrostatic screening at the outer radius of the insulation - in this case to prevent stress concentations which might otherwise be caused by the cable's outer metallic components. The insulation screen generally consists of a combination of carbon-black paper tapes and metallised paper tapes to a thickness of around 0.7 to 0.8 mm. Overlying this screen is a nylon or rayon tape threaded by a number of tinned copper wires. This tape acts as a heat barrier to protect the insulation during the lead extrusion process. The tinned copper wires provide electrical contact between the insulation screen and the lead sheath.

Lead Sheath : A hermetic metallic sheath is always required with paper insulated cable systems. Lead is the preferred material for long submarine cable lengths mainly because of the reliability of the lead extrusion process which has to operate continuously without interruption for a periods of up to three weeks during the sheathing of a single manufacturing length. It is also true that lead has some advantage over aluminum, which is used extensively for the sheathing of land cables, in terms of marine corrosion resistance. The thickness of the lead sheath varies according to the cable diameter but generally will lie between 2.5 and 4.5 mm.

Polyethylene Sheath : The thickness of this sheath again depends on the cable diameter but can generally be expected to be between 3 and 5 mm. A standard cable sheathing grade of polyethylene is usually used having a low melt flow index of around 0.2 and coloured black by the addition of 2 to 2.5% of carbon black which provides protection against UV deterioration.

Steel Tape Reinforcement : The reinforcement is applied over the polyethylene sheath and a fabric bedding layer. Two tapes are applied with a 50% displacement so the the upper tape covers the "butt gap" between contiguous turns of the lower tape. Each tape has a thickness in the order of 0.3 mm and in the case of a singe wire armor the helical lay is opposite to that of the armor to provide an anti-twist action.

Bedding Layer : A textile and polypropylene tape bedding layer having a thickness of between 1.5 and 2.5 mm is applied between the steel tape and and the armor wire. In the case of a single wire armor it has been shown that this bedding layer plays an important role in preventing kink formation during cable laying. Such kink formation can occur if there is a sudden loss, for any reason, of cable tension.

Armoring : The armor type chosen for the present study - a single layer of 6 mm diameter galvanized steel wires was preferred to the double contra-directional round wire armor, shown in Figurel, which is mandatory for sea water depths greater than around 300 m to mitigate torsional effects.

Outer Serving Layer : An outer serving, 5 - 7 mm in thickness, consisting of polypropylene string is applied as the outer layer of the cable. This layer protects the steel wires and particularly the galvanized coating from damage during transport and laying. As additional protection the armor wires are flooded with bitumen.

The type of cable just described is suitable for use at voltages of up to 400 kV and power transmission levels of up to 500 MW per single cable. The Baltic Cable (see Table 7.2) at 450 kV and 600 MW is rather a special case in that standard international test procedures were relaxed by agreement between the client and supplier.

The maximum length of HVDC mass-impregnated cable in service is 250 km, which will soon be superceded by the Bakun HVDC submarine link between Sarawak and Peninsular Malaysia a distance of over 650 km. At present there are no known length limitations and links having lengths greater than 1000 km are being considered.

Expected transmission losses for a transmission capacity of 500 MW at 400 kVDC would be less than 1% per 100 km route length.

7.1.2 The High Voltage AC (HVac) Option

HVac submarine cables are limited in length to several tens of km due to the capacitance charging current. In contrast to the HVDC case where only one cable type can be regarded as suitable for long distance submarine power transmission the following cable types can all be considered as options viz.,

- extruded cables
- SCF'F cables
- SCGP cables

Interestingly enough the mass impregnated cable is not suitable for ac applications at voltages much above 60 - 70 kV. Of the three possibilities SCF'F cables are most suitable for the highest voltages and power transmission requirements (see Table 7.4) and are generally considered to provide the most cost effective and technically reliable solution. For this reason only SCFF cables have been considered in the present study.

The construction of an ac submarine cable is similar to that of the HVDC MI cable with the following exceptions :

- 1. The impregnant is a low viscosity synthetic liquid - an alkylbenzene - which must be maintained under pressure at all times. Pressure control is achieved by fluid pumping stations which can be placed at one or both cable ends as necessary.

- 2. The copper conductor has a central fluid duct to allow fluid flow, generated by thermal expansion and contraction of the fluid under load cycling, between the cable and the pumping station(s).

-3. The galvanized steel wire armor is replaced with copper wire of the same (6mm) diameter to reduce the circulating current losses which severely limit the cable ampacity at power levels of 200 MVA and above.

TABLE 7.4: EXAMPLES OF RECENT HVAC SUBMARINE CABLE INSTALLATIONS

NAME OF LINK*	DATE	VOLTAGE kV	POWER MVA	LENGTH km
1. Malaysia - Langkawi Island	1986	132	100	27
2. Spain - Morocco	1995	400	300	26
3. Italy - Sicily (Messina Straits)	1993	400	600	6.5
4. British Columbia - Vancouver Island	1983	525	1200	40
5. Long Island Sound	1990	345	N/A	15
6. Greece - Ionian Islands	1985	150	125	20
7. Alaska - Cook Inlet	1990	138	N/A	7
8. Boston - Deer Island	1990	115	N/A	7
9. Lake Shetek - Minnesota	1985	69	N/A	1.7

* All of the cable links appearing in the Table use SCFF cables with the exception of the Lake Shetek installation which uses an XLPE, lead sheathed and steel wire armored cable. The author is not aware of any links with XPLE cables operating at voltages greater than 69 kV.

7.2 THE SUBMARINE CABLE DESIGN STUDY

7.2.1 Study Objectives

The principal objectives of the present (1995) design study are fourfold viz.,

(i) To design an HVDC submarine cable capable of transmitting 500 MW over a distance of 100 km in a riverbed environment

(ii) To develop costs for the HVDC submarine cable, for transport and laying, and for protection. by embedding the cable in the river bed

(iii) To design HVAC submarine cables capable of transmitting 500 MVA in a riverbed environment at 230 kV and 345 kV and determine the critical length in each case

(iv) To develop costs for the HVac submarine cable, for transport and laying, and for protection by embedding the cable in the river bed

7.2.2 Design Parameters

The design parameters, which can be regarded as typical for the type of installation envisaged, used in the present study are summarized as follows:

7.2.2.1 External Parameters

System Transmission Voltages	400 kV (dc), 345 kV (ac)
Basic Impulse Levels (BIL)	960 kV (dc), 1300 kV (ac)
Transmission Powers	500 MW per cable (dc), 500 MVA per circuit (ac)
Route Length	100 km (dc), Maximum Possible (ac)
Maximum River Bed Temperature	25 °C
Burial Depth (in River Bed)	1.0 m
Phase Spacing	6.0 m (ac case only)
River Bed Thermal Resistivity	1.0 °C-m / W

7.2.2.2 Internal Parameters

Maximum Conductor Temperature:	50 °C (dc), 85 °C (ac)
Max. Steady State Electrical Stress:	30 kV / mm (dc), 14 kV / mm (ac - rms)
Max. Transient Electrical Stress :	95 kV / mm (dc and ac)

7.2.3 Study Results - The HVDC Scenario

The results of the HVDC submarine cable design and budgetary costing study are summarized below:

- **CABLE DIMENSIONS AND WEIGHTS**

CONDUCTOR CROSS SECTION	mm^2	1400
INSULATION THICKNESS	mm	18.0
LEAD SHEATH THICKNESS	mm	3.4
POLYETHYLENE SHEATH THICKNESS	mm	4.1
GALVANIZED STEEL-WIREDIAMETER	mm	6 . 0
OVERALL CABLE DIAMETER	mm	119.0
APPROX. CABLE WEIGHT IN AIR	kg / m	44.2
APPROX. CABLE WEIGHT IN WATER	kg / m	32.5

- CABLE ELECTRICAL DETAIL

RATED POWER PER CABLE	MW :	500
RATED CURRENT	Amps :	1250
CONDUCTOR JOULE LOSSES(for 100 km on way)	Mw :	2.0
CONDUCTOR JOULE LOSSES (for 30 km one way)	MW :	0.6
VOLTAGE DROP (for 100 km)	kV :	1.6
VOLTAGE DROP (for 30 km)	kV :	0.48
CONDUCTOR RESISTANCE	Q/km :	.0129
SELF INDUCTANCE	mH / km :	.168
CAPACITANCE	µF /'km :	.355
DC CONDUCTOR SCREEN STRESS(NO LOAD)	kV / mm :	23.1
DC INSULATION SCREEN STRESS (FULL LOAD)	kV / mm :	23.1
DC PLUS REV. POLARITY BIL	kV / mm :	80.8
DC POLARITY REVERSAL	kV / mm :	61.1
IMPULSE STRESS AT BIL (NO DC VOLTAGE)	kV /mm :	73 .4

- **BUDGETARY COST DETAIL**

HVDC SUBMARINE CABLE UNIT COST	$US / m :	565
TRANSPORT / INSTALLATION UNIT COST	$US / m :	53
EMBEDDING UNIT COST	$US / m :	15
TOTAL INSTALLED CABLE UNIT COST	$US / m :	**633**
TOTAL COST PER 100 km CABLE	$MUS :	**63.3**
TOTAL COST PER 30 km CABLE	$MUS :	19.0

From the above results if can be concluded that the electrical design is on the conservative side as both the steady state dc and the (worst case) transient electrical stress both have adequate margins with respect to the maximum permissible design values. It would in principle be possible to reduce the insulation thickness below the proposed value of 18 mm. However, there would be negligible cost advantage in so doing since the cost of raw materials accounts for only around 15 % of the cable cost. Additionally, the reduction in insulation thickness would not significantly change the power transmission capability.

The budgetary costs given above were developed using PTI's cost algorithm which has recently been used in a comparison with data received from the principal HVDC submarine cable manufacturers and found to be in good agreement.

The above cost data do not include the cost related to provision of a return ground current path. The normal practice in the *case* of a submarine monopolar installation is to use a sea return with a sea cathode and either a sea or a beach anode. The cost of sea electrodes and electrode cable would be in the range of $US 3 million to $US 5 million. In principle this solution can also be employed for a land based dc transmission cable system. Other approaches would be to use a return cable - this would typically be an XLPE insulated cable with a much smaller conductor than the main HVDC cable, a lead sheath and steel wire armor, and a voltage rating of around 69 kV. The installed cost of such a cable would be in the range of $US 150 per meter and this solution would increase the project cost by 25 %.

A bipolar solution avoids the need for a return current path - unless required to provide monopolar transmission in case of an outage of one of the cables. In the present case the bipolar configuration would be capable of transmitting 1000 MW and the cost would be exactly double that of the monopole.

7.2.4 Study Results - The HVac Scenario

The results of the HVac submarine cable design and budgetary costing study are summarized below:

- **CABLE DIMENSIONS AND WEIGHTS**

CONDUCTOR DUCT DIAMETER	mm	24
CONDUCTOR CROSS SECTION	mm^2	800
INSULATION THICKNESS	mm	20.5
LEAD SHEATH THICKNESS	mm	3.5
POLYETHYLENE SHEATH THICKNESS	mm	5.1
COPPER Armor WIRE DIAMETER	mm	6.0
OVERALL CABLE DIAMETER	mm	127.5
APPROX. CABLE WEIGHT IN AIR	kg/m	26.5
APPROX. CABLE WEIGHT IN WATER	kg/m	13.3

- **CABLE ELECTRICAL DETAIL,**

RATED POWER PER CABLE CIRCUIT	MW	625
RATED CURRENT	Amps	1042
CONDUCTOR JOULE LOSSES	W/m	31.3
DIELECTRIC LOSS	W/m	10.3
SHEATH/ Armor LOSSES	W/m	13.6
CONDUCTOR AC RESISTANCE	Ω / km	.0287
EQUIVALENT STAR REACTANCE	Ω / km	.447
CAPACITANCE	μF / km	.284
CHARGING CURRENT	A/km	21.4
AC STRESS	kV / mm	13.8
IMPULSE STRESS AT BIL	kV /mm	89.9

- **BUDGETARY COST DETAIL**

HVAC SUBMARINE CABLE UNIT COST	$US / m	420
TRANSPORT / INSTALLATION UNIT COST	$US / m	40
EMBEDDING UNIT COST	$US / m	15
TOTAL INSTALLED CABLE UNIT COST	$US / circuit m	1425

The costs quoted have been based on recent but limited data received from a single manufacturer and therefore can be considered only as indicative.

The HVAC cable proposed for the present scenario has been designed to transmit a maximum power equal to 625 MVA This allows a margin of 125 MVA to compensate for the heating effect of the cable's charging current which effectively reduces the power rating - eventually to zero as the circuit length increases. This effect has been calculated in the present case and the result is shown in Figure 7.1. That figure shows that the critical length of the 345 kV ac cable under consideration is in the order of 48 km and that the required transmitted power of 500 MVA can only be achieved at distances of up to 30 km. Transmission losses are high in the ac case amounting to nearly 5 MW for the 30 km circuit length compared with the equivalent dc case where the losses would be approximately 0.6 MW for the same transmission distance.

The above described 345 kV submarine cable design study has focussed on the electrical aspects of cable design only. The hydraulic design would require to be worked out in detail - a non trivial problem - before the proposed design could be confirmed for the 30 km circuit length suggested. The hydraulic design may prove to be limiting and the circuit length would have to be reduced even further than required by electrical considerations. The analysis is nevertheless useful in that it illustrates what is found in practice namely, that high voltage ac submarine (or underground for that matter) circuits longer than about 30 to 40 kms cannot be considered and in fact do not exist. Power transmission at longer distances inevitably requires recourse to HVDC.

7.3 SUMMARY

For technical reasons, submarine applications exceeding about 50 km, and some underground applications, dc cables are the only option. For most underground and all short submarine cable applications, both ac and dc options are feasible. The economics frequently favor dc even for short lengths. The one cable example considered in the break-even distance analysis of Section 6 indicated that ±400 kV dc was more economical than 345 kV ac for distances greater than about 30 km. The examples cited in this section confirm those findings and provide include detailed design information for completeness. The list of submarine cable applications provided in Table 7.3 is destined to grow dramatically in the next few years. The Bakun project will include the longest (650 km) submarine cable so far and no fewer than seven new cable connections between the European mainland and Nordic countries are under construction at the time of this report. The increased volume and resulting competition between cable manufactures should lead to increased technology and lower prices. This should be to the benefit of U.S. transmission developers in the near future. Underground and submarine dc cable systems might provide great opportunityto transmission planners faced with serving increased loads simultaneous with shrinking ROW opportunities for overhead lines.

8. ASYNCHRONOUS LINKS

As discussed in Section 3.2, there will be need for additional back-to-back dc links to increase the interchange capacity between existing networks in the U. S . and to adjacent Quebec and Mexico. Some of the added interconnecting dc projects may involve dc lines as well. This section discusses one example of a future back-to-back that is the subject of a parallel development project [Project 2000,1995] and speculates on additional needs for asynchronous links.

8 . 1 PROJECT 2000 - AN EXAMPLE

A parallel DOE-sponsored development program called "Project 2000" seeks to implement one or more dc back-to-back links incorporating voltage-source-converter VSC technology by the year 2000. Under the leadership of Western Area Power Administration, prospects for five possible back-to-back (east-west) interconnectors were evaluated. Preliminary feasibility studies (power flow) were done to assess the active and reactive power needs and capabilities of each candidate location.

One of the promising applications is an interconnection between a 230 kV substation at Lamar, Colorado and a 345 kV station (Holcomb) near Garden City, Kansas. The proposed interconnection includes a 345 kV line from Holcomb to Lamar, a distance of about 90 miles. A back-to-back dc facility would connect the new 345 kV line to the 230 kV system at Lamar. Studies have shown [project 2000,1995] that the two associated ac systems could accommodate 400 MW east-to-west and up to 300 MW west-to-east. The dc facility would need to provide from 60 MVAR to 148 MVAR (for 300 MW west-to-east transfers) to the west-side system for voltage support. A VSC design would be desirable, but not absolutely necessary to make this feasible.

An economic justification for interconnection was no-doubt conduced but was not documented in the above reference. An analysis included in this report provides a crude economic justification of that interconnection, assuming 400 MW east-to-west transfers as the primary operating mode. The assessment herein assumes that utilities (including Public Service of Colorado) on the west side of the interconnection could benefit from low cost energy available in western Kansas.

> At the time of this writing, a pending merger between Public Service of Colorado PSC and Southwest Public Service SPS of Amarillo, Texas may result in a 400 MW interconnection over a 300 mile 345 kV line plus a back-to-back dc link at the Texas end.

Three options are evaluated below: 1) the ac line and dc back-to-back facility as described above, 2) a dc line instead of the 345 kV ac line, and 3) installation of a gas-fired combined cycle power plant rated 400 MW at Lamar.

Option 1. 345 kV ac line and 400 MW Back-to-Back dc

The technical and economic advantages of this scheme were discussed in general terms by Hammad and Long [Hammad, 1990] while this report considers the economics only. Unless specifically stated, the line costs and dc costs (in 1996 dollars) presented in Section 4 and used in Section 6 for computing the break-even- distance estimates are used in this analysis. The cost of losses over an assumed 30 year economic life of the facilities is assumed to have a present worth of $2000/KW. Three new ac substations are assumed, in addition to the full dc back-to-back converter station, with costs as assumed in Section 4.3.
The major cost elements are:

- 90 mi. of 345 kV at $600K per mile	$54 MM
- 400 MW B-B dc turn-key at $100/KW/side	$80 MM
- Indirect costs about 25% of turn-key costs	$20 MM
- Three new 400 MW ac substations at $10/KW	$12 MM
- Line losses at $156K/mile for 90 miles	$14 MM
- AC substation losses (0.5%) 2 MW per sub	$12 MM
- DC converter losses (1%) 4 MW per side	$16 MM
Total Projected Cost	$208 MM

Option 2. Appropriate dc line instead of ac line

The incremental cost increases and reductions below build on Option 1. The converters cost more for the higher voltage, as seen in Figure 4.1.

- Increased (40%) converter costs for ±250 kV	+$32.0 MM
- Save 20% of line construction costs	-10.8 MM
- Eliminate one ac substation - capital cost	- 4.0 MM
- Added costs for higher dc voltage, dc filters, etc.	+6.0 MM
- Losses saved by eliminating one ac substation	- 4.0 MM
- Savings in line losses (30% of $14 MM)	- 4.2 MM
Net (increase)	$15.0 MM
Total Projected Cost	$233 MM

Option 3. New 400 MW Gas-Fired CC Plant at Lamar

Lamar appears to be only about 10 miles from a 20 inch gas pipeline (Figure 8.1) so this analysis assumed that a new 10 mile tap of 15 inch diameter pipe would be required to serve the power plant from the existing gas source. The analysis further assumes that a 2000 HP booster pump in the existing 20 inch main will suffice for accommodating the power plant's needs. Of course, a thorough study of the present pipeline capacity and pressure conditions would be required to confirm this assumption. A booster pump at the plant is included in the estimated plant costs.

Option 3 involves:

- Gas-fired Combined Cycle plant with 2x200MW assuming $800/KW includes a 2000HP pump, financing, etc.	$320 MM
- Ten miles of 15 inch pipeline at $500K/mile [EPRI TR-104787] . .	5 MM
- One 2000 HP booster pump in 20 inch main at $2000/HP............	4 MM
Total Projected Cost	$328 MM

Comparing the three options, the new power plant is the most expensive, even if the gas pipeline additions shown were not needed.

Of the two transmission line options, the ac line approach appears to be slightly less expensive. Building the dc line as a monopolar line with a metallic return conductor with lower insulation requirements might lower the cost. However, higher voltage or higher current will be required for the same power, so increased costs (especially for losses) would offset any savings. Eliminating the metallic return in favor of full-time earth return probably would also suffer, offsetting costs for higher losses (higher current) plus the cost of deep-earth-electrodes. Since the line is only 90 miles, the cost of the second conductor probably would be less than the cost of electrodes. Furthermore, the presence of many gas pipelines (and no-doubt other oil and refinery product lines) over half of the length of the line (see Figure.8 1) would drive the cost of interference mitigation up - see companion Fii Report for Part IIB of this research entitled "HVDC Power Transmission - Electrode Siting & Design".

Lastly, the prospects of possibly tapping the line in the future favors the ac line. Therefore, the first option appears to be the least costly of those considered. Next, a rough-cut study of the potential cost savings associated with purchasing power from Kansas is worth while.

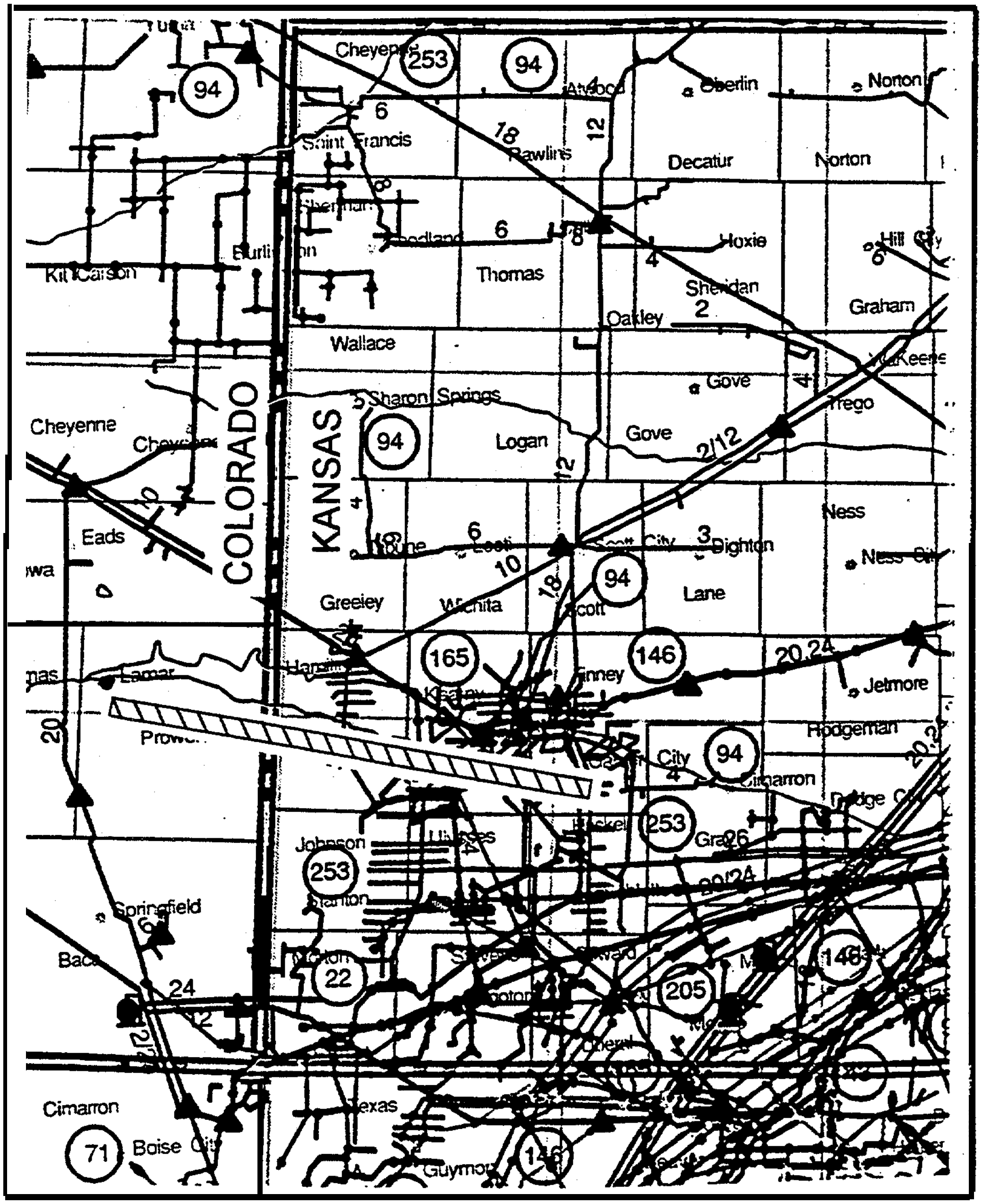
Estimated Pay-Back Period of Option I.

The potential financial benefits of interconnecting with western Kansas is that PSC might be able to purchase less costly energy from Sunflower Electric Company SUNC. Data provided in a report by Resource Data International, Inc. [RDI, 1995] included the following average incremental costs (lambdas) for PSC and SUNC.

PSC - summer 1993	....	$11.72 /MW-hr
winter 1993	....	$13.52 / MW-hr
SUNC - summer 1993	....	$9.80 / MW-hr
winter 1993	....	$10.53 / Mw-hr

The differential energy costs are . . . . $1.92 / MW-hr in summer
and .... $2.99 / MW-hr in winter

in favor of PSC purchasing from SUNC.



Legend:

Possible Route of ac or dc Line

Figure 8.1 - Pipelines in Colorado/ Kansas and Possible Lamar - Garden City Electric Transmission Line

Assuming this level of energy savings over the life of the line (a bold assumption in light of the growing competition in the industry) and sufficient (400 MW) excess capacity available all that time, the following analysis is offered.

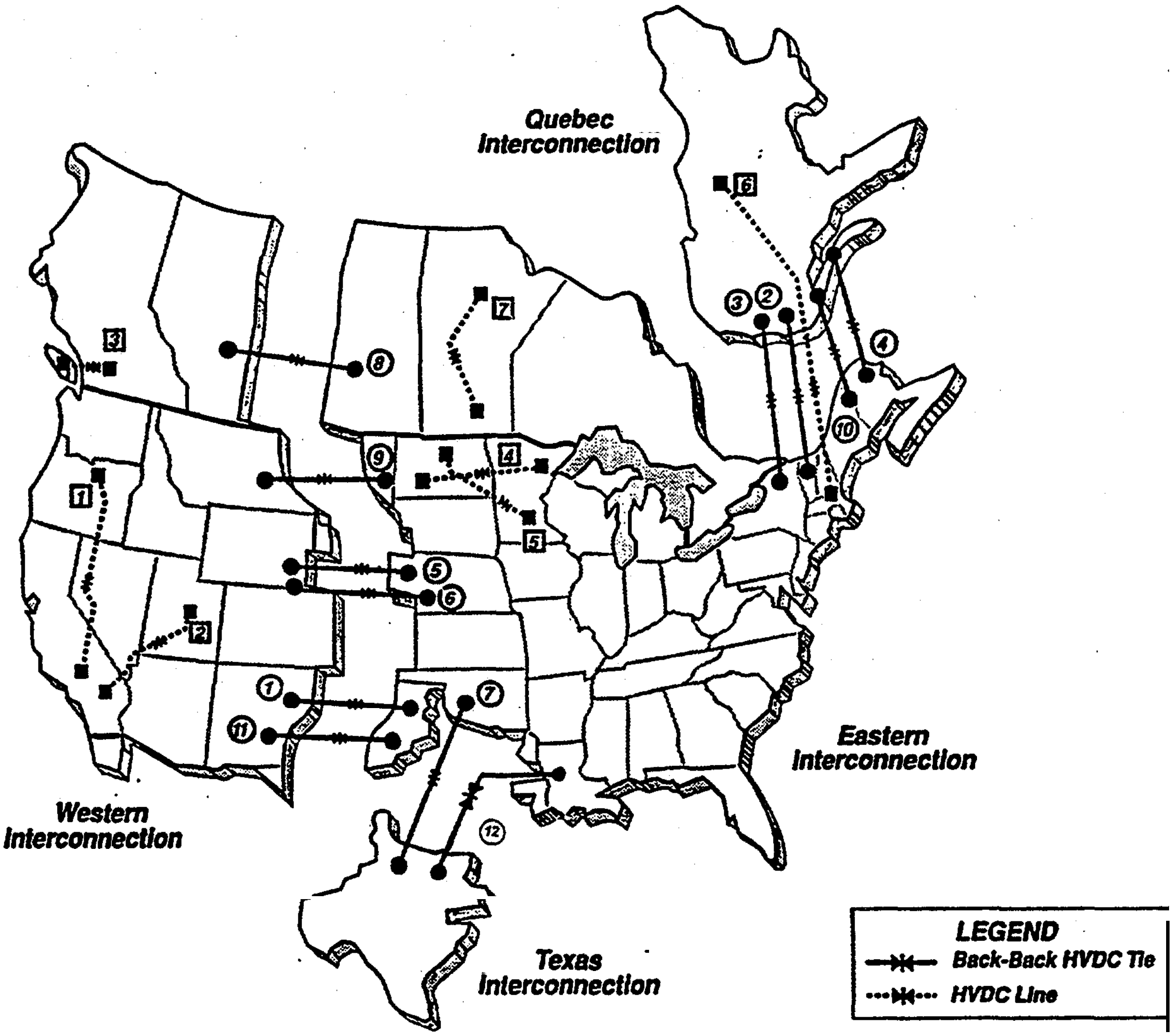
Assuming 80 % load factor on the line, then 400 MW will be transferred for about 6000 hours a year. Splitting that evenly between summer and winter, yields an energy (fuel cost) savings to PSC of about $5.9 MM per year. The $208 MM cost of Option 1 project will be recovered in 35 years. If the converter costs are reduced by 50% in time for this project, the $40 MM reduction in Option 1 cost reduces the pay-back period to 28 years. Both estimates yield approximately the 30 year asset life assumed in the loss estimating. Option 1 appears to be financially feasible within the confines of the assumptions used in this analysis.

8.2 DECREASING SYNCHRONIZING CAPACITY - REINFORCE OR SPLIT

The capacity of transmission lines interconnecting utilities, pools or regions must be able to accomodate scheduled power transfers, of course. However, ac electrical ties between regions must also provide adequate synchronizing capability. If synchronizing capability is not available, large inadvertent power flows and/or voltage excursions may result, and loosely tied regions may even pull out-of-step. This is why the WSCC member utilities (see Figure 8.2) are not interconnected by ac lines with MAPP, SPP, and ERCOT utilities. Experience suggests that for adequate performance, the synchronizing capability between two regions must equal at least 10% of the installed capacity of the smaller region. Synchronizing capacity between regions is needed even if there is little or no net power transfer on the ties.

The location of new generation is probably the greatest uncertainty limiting accurate prediction of long term transmission needs. One possibility is that most new generation will be located close to the load so power transfers on inter-regional ties will not increase significantly. The present trend is to use gas-fired generation located close to the load with less reliance on large hydro, coal-fired or nuclear plants located some distance from the load. Increased development of fuel cells, small solar plants and other distributed generating technologies might accelerate the trend toward local generation. If mostly local generation is added and the competition in generating resources gives rise to adequate in-region reserve capacity, new transmission ties between regions may not be needed for power transfer alone.

However, if new electrical ties are not added for energy exchange, the synchronizing capability across existing transmission interfaces could eventually become inadequate as load and the local generation grows. Applyiong FACTS may incrementally improve the synchronizing capacity for a time but eventually, new circuits will be necessary. Therefore, use of local generation can not put off the need for transmission additions or enhancements indefinitely. The following analysis shows that if local generation meets the predicted rate of load growth over the next 25 years, and no major transmission reinforcements are made, synchronizing capability across some US interfaces could become inadequate. If this occurs either the ac transmission will have to be reinforced or the system will have to be divided into



BACK-BACK HVDC TIE

1 1 Biackwater (ZOO MW)
2 2 Highgate (200 MW)
3 3 Chateauguay (1000 MW)
4 4 Eel River (320 MW)
5 5 Hamil (100 MW)
6
7 67VirginiaOklaunionSmith(200(200MWMW)
8 8 McNeill (150 MW)
9 9 Miles City (200 MW)
10 10 Madawaska (350 MW)

8 121Artesia East Texas (200-MW) Welsh (600 MW)

HVDC LONG DISTANCE TRANSMISSION SYSTEM

1 Pacific HVDC Intertie (3100 MW)
2 IPP (1920 MW)
3 Vancouver Island (682 MW)
4 CU (1000 MW)
5 Square Butte (500 MW)
6 Hydro Quebec - New England (2250 MW)
7 Nelson River (3668 MW)

Figure 8.2 - North American Asynchronous Systems. and HVDC Connections

two or more asynchronous parts. Some power exchange between the asynchronous regions could of course be provided by HVDC.

8.2.1 Two Examples

The synchronizing capabilities across two selected US interfaces were estimated to see if those interfaces, left unimproved, will remain adequate in the face of predicted load and generation growth for the next 25 years. The interfaces selected for this analysis were determined by examining a high voltage transmission map of the US in search for interfaces that include as few lines as possible. Two such interfaces were identified. The first, described with the help of Figure 8.3, splits the eastern interconnection approximately along the Mississippi River. That split starts in northern Wisconsin, proceeds south to the Mississippi River near La Cross Wisconsin, follows the river to the Tennessee border where it then turns west across Arkansas to the northeast comer of Texas and finally turns south, roughly following the border of Texas to the Gulf of Mexico. The transmission lines cut by this split are listed in Table 8.2.1. The second split identified separates the MAPP reliability district from the rest of the eastern US interconnection. That possible split is also shown in Figure 8.3 and the lines it cuts are listed in Table 8.2.2.

Isolation of MAPP- A New MAPP Interface?

The Federal Energy Regulatory Commission, FERC, 1994 summer peak load flow databases for the MAPP and SPP regions were used to estimate the synchronizing capability across the selected interfaces. Table 8.2.2 shows the approximate synchronizing capacity contributed by each tie line for the MAPP interface. These estimates of synchronizing capacity were computed as proportional to the reciprocal of a representative impedance multiplied by two Thevenin voltages representing the separated subsystems. The"representative impedance is made up of the line impedance plus two approximate Thevenin impedance's representing the two separated subsystems. In some cases closely coupled tie lines are grouped. For the MAPP interface, the total synchronizing capacity was computed to be 7,188 MVA, as noted in Table 8.2.2. Of this total, approximately 38% is provided by three lines. About 1,860 MVA is provided by 2-345 kV lines to SPP from Nebraska Public Power District's Cooper substation. Another 850 MVA is provided by a 345 kV line from Northern States Power's Eau Claire substation to MAIN.

The 1994 summer peak load for MAPP was 3 1,800 MW. The North America Electric Reliability Council, NERC, estimates that the load in this region will grow at a rate of 1.8% through 2004. Therefore, the load should reach 50,600 MW by 2020 if this modest rate of growth continues. With all circuits in service the synchronizing capacity, 7,187 MVA would still be more than 13% of this 2020 peak load. With one circuit out, synchronizing capacity would be a little less than 12% and with the two Cooper lines out, the synchronizing capacity would be approximately 10% of the peak load, at the threshold of potential trouble.

Another East - West Split; New "Mississippi River" Interface?

Table 8.2.1 shows the approximate synchronizing capacity contributed by each tie line for the "Mississippi River" interface. For that interface, the total synchronizing capacity is estimated to be 13,400 MVA. Of this approximately 2,800 is provided by two 500 kV lines, one from Oklahoma Gas and Electric and the other from Associated Electric Power Cooperative.

The 1994 load for the region separated by the "Mississippi River" interface is 71,800 MW. With load growth of 1.8% per year the load will reach 114,200 MW by 2020. With all circuits in service the synchronizing capacity, 13,400 MVA, will be 11.7% of peak load. With the one 500 kV circuit out the synchronizing capacity will be marginal, 10.4%. With two 500 kV circuits out the synchronizing capacity will be approximately 9.3% of peak load. Using the rough 10% rule-of-thumb, this probably would not be adequate.

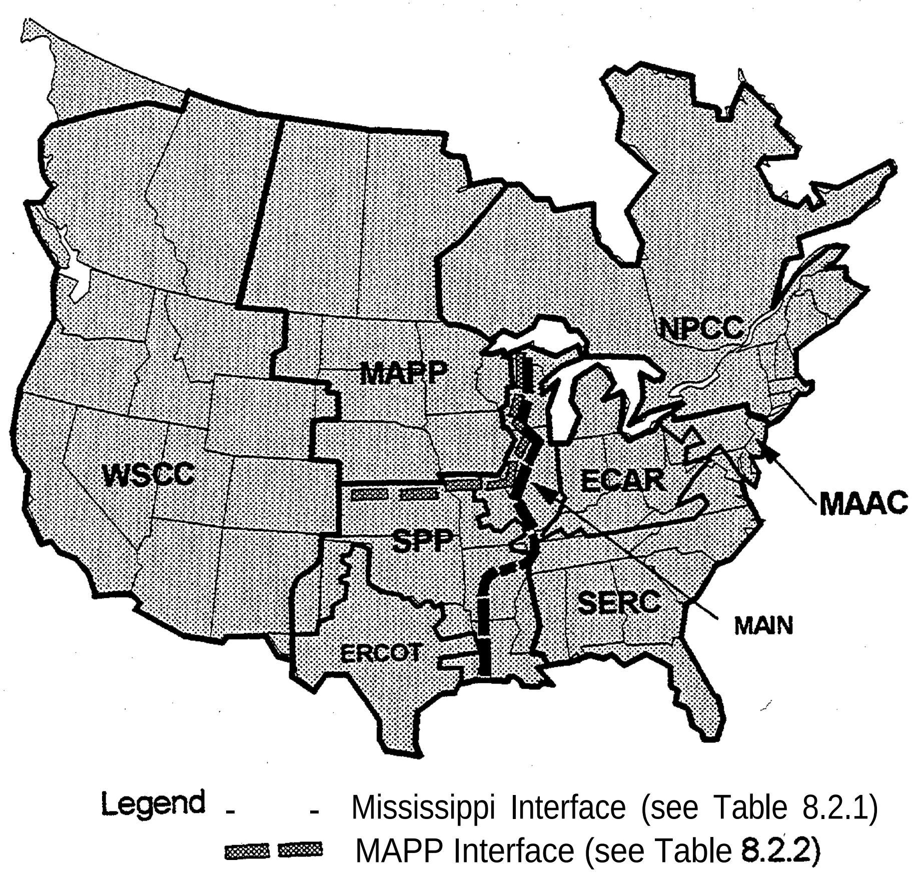


Figure 8.3 - Two Possible Future Asynchronous "Splits" in Eastern U.S. Network

This crude analysis suggests that there are at least two interfaces where the US transmission grid may need to be reinforced by the year 2020 to maintain adequate synchronizing capability even if reinforcement isn't required to support additional loading. This analysis did not seek the most critical case or attempt to identify the full extent of the problem. It is very likely that there are weaker interfaces than the ones selected.

8.2.3 Options

If synchronizing capacity diminishes to unacceptable levels, two options can be considered. The first would be to provide equipment or transmission so the system can continue to run synchronized. The second would be to split the system into asynchronous regions. If the system is split, power transfer between asynchronous regions might still be provided using HVDC connections. Both options would involve an investment and the least cost option may be the best option at the time. In some cases the ac reinforcement might involve a rather long ac line to tie to relatively strong buses. The insertion of a back to back into an existing line could be less costly.

A third hybrid option might be appropriate depending upon the circumstances. Rather than split the interface, a back to back HVDC or an HVDC line with special synchronizing controls could be added in parallel with existing lines across the interface. Although untried to date, a synchronizing controller responsive to angle differences [Street,1994] across key (parallel) ac synchronizing ties might act similar to an ac line yet possess the other advantages of HVDC. The voltage phasor angles at two or more key buses on both sides of the interface might be measured and communicated to the HVDC. The HVDC power could be "programed" to respond similar to an ac line (the familiar sinusoidal power vs angle relationship) thereby adding synchronizing strength to the interface. HVDC power modulation controls that add damping to power swings on parallel ac systems are a proven technology. They act in response to the difference in measured frequencies at the two ends of the HVDC link. The synchronizing control would use angles instead of frequencies. The technology for measuring ând communicating voltage phasor angles at long distances is maturing. Some schemes in trial use today involve use of satelite communications. The strength of the synchronizing contribution could be adjustable to some extent, acting siiar to a controlled series capacitor in an ac circuit.

In more general terms, some of the reasons for being interconnected such as frequency stabilization and sharing spinning reserve, may become less important as the individual subsystems grow in local generating capacity. A detailed analysis of the relative benefits of the options is beyond the scope of this study but the level of energy and power exchange would be an important consideration. Tables 8.2.1 and 8.2.2 include the power exchanges across the subject interfaces for the 1994 summer peak base case loading conditions. The total interchange is 1,743 MW for the 'Mississippi River" interface and 369 MW for the "MAPP interface". From an overall system perspective, these transfers are rather modest. Perhaps some of the interchanges across the perceived splits could be sacrificed to avoid the expense of reinforcing the interface. Alternatively, strategically located, small HVDC back to back links could maintain the more critical transfers while avoiding major ac transmission reinforcements.

While the above analysis and discussion are highly speculative, they serve to highlight another possible challenge facing transmission planners. The notion of making strategic splits in the network instead of simply continuing the expansion of the ac grid at all cost may seem extreme. However, the business environment of the electric power industry is also undergoing extreme modifications so the solutions to technical challenges in the future may need to be bold as well.

8.3 *SUMMARY*

Back-to-back converter stations and dc lines are the only practical way to interconnect asynchronous ac networks at this time. There is no reason to believe that this will change in the next 25 years. Also, the current state of voltage source converter technology is very close to being economically practical for modest sized (e.g. 100 MW) back-to-back applications. Indeed, a parallel development project (Project 2000) is considering such an application. An increase in the use of back-to-back dc interconnections between existing networks is foreseeable once the VSC technology is cost effective. Also, there is a remote possibility that additional splits in today's four ac networks could be justified whereupon new dc links between them could be needed.

Table 8.2.1. Tie Lines for "Mississippi River" Interface

Utility	Bus Name	Rated kV	Bus Name	Rated	Synchronizing	Loading
Southwestern Electric Power Co	SOEP		CELE			
	sw shv 7	345	dolhill 7	345	610	-441
	wallake 4	138	mansf 4	138	51	-56
					661	-497
	SOEP		ENTR			
	eureka	161	osage	161	5	85
	hope	115	patmos#3	115	100	-46
	nmagzin	161	danvi	161	83	-26
	snashvl 4	138	murfre 4	138	74	-22
	longwd 7	345	eldehv 7	345	740	-87
	pirkey 7	345	grims 7	345	416	156
					1418	60
Southwestern Power Adm	SWPA		ENTR			
	jonesbo5	161	jones 5	161	186	-103
	hergett5	161	jonetp*5	161	0	-55
	hergett5	161	bay 5	161	79	-11
	greersf5	161	hebr-n#5	161	76	66
	water v5	161	wy-apl 5	161	0	27
	norfork5	161	calcr5	161	200	-32
	norfork5	161	soland#5	161	0	-2
	bull sh5	161	bullsh*5	161	6	201
	dardane5	161	dardan 5	161	0	68
	dardane5	161	rusl-s 5	161	107	23
					654	182
Oklahoma Gas & Electric	OKGE		ENTR			
	ftsmi8	500	ano 8	500	1338	-251
Empire District Electric Co	EMDE		ENTR			
	oz dam 5	161	omaha *5	161	11	6
Associated Electric Coop	ASEC		ENTR			
	wplain	161	thay-s 5	161	71	-6
	newmad	500	dell 8	500	1477	313
	newmad 5	161	prtgvl 5	161	0	118
	gibson5	161	jimhl 5	161	30	74
	grnfrt 5	161	jimhl 5	161	29	-23
	alton 2	69	thay-n	69	0	-11
					1607	465
	ASEC		TVA			
	newmad 5	161	new tip	161	332	63

Table 8.2.1. Tie Lines for "Mississippi River" Interface - CONTINUED						
Utility	**Bus**	**Rated**	**Bus Name**	**Rated**	**Synchronizing**	**Loading**
Jnion Electric	UNION		MAIN			
	palmyra	161	marbhd n	138	0	119
	cape gir	161	joppa s	161	213	-225
	cahokia	345	baldwin	345	224	-576
	cahok 1	138	n c oultr	230	410	-42
	cahok 3	138	cntry tp	138	457	-38
Jnion Electric - continued	venice 1	138	am st tp	138	439	32
	venicet	69	gc steel	69	68	5
	venic 2	13.8	madstate	138		-4
	venic 3	13.8	madstate	138	12	-1
	roxford	345	roxfd tp	345	84	-356
	roxford	138	wood r n	138		-73
	roxford	138	wood r s	138	996	-65
	e.quincy	138	quincy e	138	91	-10
	s.quincy	138	quincy s	138	108	5
	hamilton	69	appanoos	69		14
	hamilton	69	hamilto2	69	21	23
	venice	69	gc steel	69	98	34
					3221	-1158
	UNION		TVA			
	kelso	345	7shawnee	345	821	-207
Jorthern States Power	NSP		MAIN			
	t-crnrs7	115	wien	115	107	-12
	eau cl 3	345	arpin	345	850	360
nterstate Power Co	IPW		MAIN			
	albany 6	138	grdn pl	138	182	27
	rock ck3	345	quadcy	345	503	-307
)airyland Power Coop	DPC		MAIN			
	casvill5	161	nl dewey	161		-65
	seneca 5	161	nl dewey	161	363	45
	bellctr5	161	hillside	69	0	26
:IES	CIES		MAIN			
	lee	69	appanoos	69	0	-4
	lee	69	hamilton	69	28	-6
owa Illinois Gas and Electric	IIGE		MAIN			
	galesbr5	161	galesbrg	138		15
	galesbr5	161	galesbrg	138	111	17
	sub 91 3	345	quadcy	345		-338
	e molin3	345	quadcy	345	1200	-164
TOTAL					13407	-1743

Table 8.2.2. Tie Lines for "MAPP Interface"						
Utility	**Bus**	**Rated**	**Bus Name**	**Rated**	**Synchronizing**	**Loading**
Northern States Power	NSP		MAIN			
	t-crnrs7	115	wien	115	107	-12
	eau cl 3	345	arpin	345	850	360
Interstate Power Co	IPW		MAIN			
	albany 6	138	grdn pl	138	182	27
	rock ck3	345	quadcy	345	503	-307
Dairyland Power Coop	DPC		MAIN			
	casvill5	161	nl dewey	161		-65
	seneca 5	161	nl dewey	161	363	45
	bellctr5	161	hillside	69	0	26
CIES	CIES		MAIN			
	lee	69	appanoos	69	0	-4
	CIES		UNION			
	carbide5	161	carbid t	161	0	-72
	viele5	161	carbid t	161	117	50
	apanose5	161	adair	161	252	12
	carbide	69	keokuk	69	0	-13
	lee	69	hamilton	69	28	-6
Iowa Illinois Gas And Electric	IIGE		MAIN			
	galesbr5	161	galesbrg	138		15
	galesbr5	161	galesbrg	138	111	17
	sub 91 3	345	quadcy	345		-338
	e molin3	345	quadcy	345	1200	-164
	IIGE		UNION			
	sub t	345	palm tap	345	739	28
Nebraska Public Power District	NPPD		SPP			
	cooper 3	345	st joe 7	345		284
	cooper 3	345	fairpt 7	345	1859	227
	redwilo3	345	mingo	345	565	260
Omaha Public Power District	OPPD		SPP			
	humbolt5	161	kelly 5	161	171	45
Wapa -Sd	WAPA-		SPP			
	creston5	161	maryvl 5	161	55	-24
Midwest Power System Cornbelt	MPSI		SPP			
	clrnda 5	161	maryvle 5	161	86	-22
TOTAL					7188	369

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APPENDIX A

SUMMARY OF PUBLISHED TRANSMISSION PLANS

The following excerpts from published reports summarize planned transmission enhancements in the US. Since the data is "dated" and is derived largely from the NERC report that focuses primarily on reliability, additional plans may exist that were not reported or may arise as economic opportunities einerge. Portions of the following discussion are also derived from the researchers' general knowledge of system issues around the US and Canada.

The data is sorted by NERC regions shown on *Figure A. I.* The report covers the years 1995 - 2004, less than half of the target period of this research.

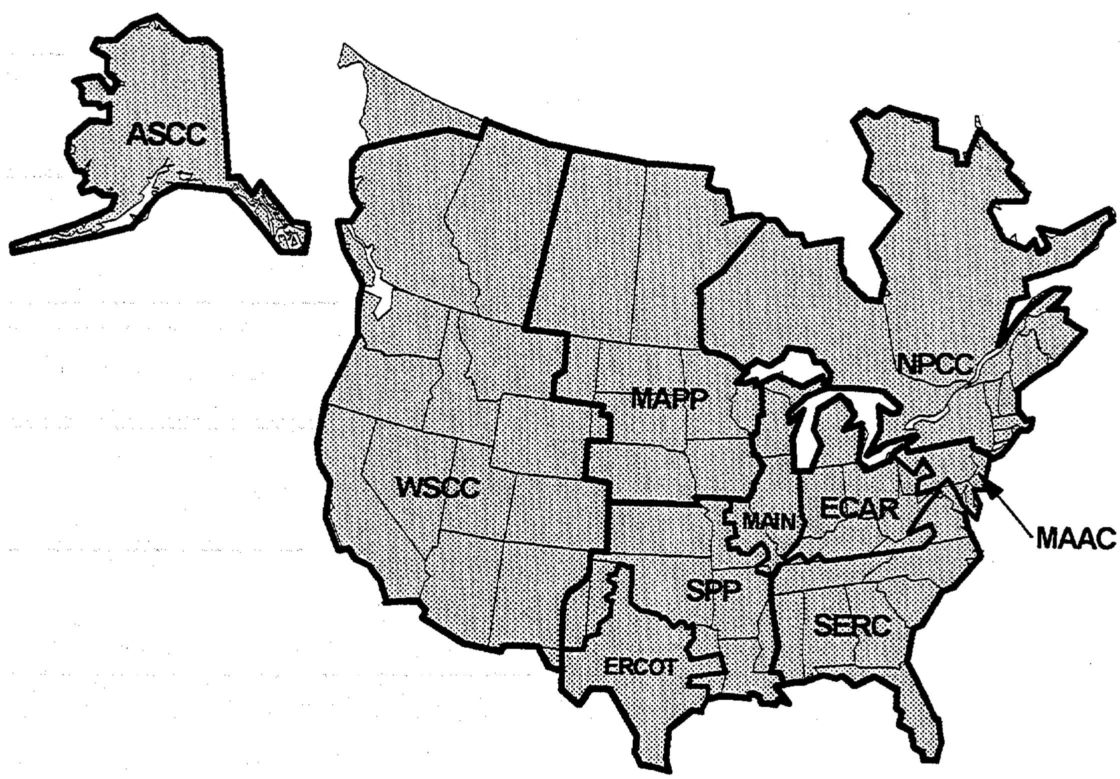


Figure A. 1 - North American Electric Reliability Council (NERC) Regions
*See text below or List **of** Acronyms **for** definitions **of regions.***

ECAR - East Central Area Reliability Council

In general, reliability will be maintained in this region through 2004. Generating capacity and reserve margins may decline due to the advancing age of many of the units. The area is 90% dependent on coal-fired units, many of which are distant from the major load centers. The transmission consists of a 765 kV backbone overlaying 345 kV in much of the central area, and 500 kV in the eastern interface with MAAC, a region cvered by the Pennsylvania-Jersey-Maryland Power Pool (PJM). Only a few additions to transmission are planned.

The reliability of the eastern interface is enhanced by a Reliability Coordination Plan (RCP), whereby key lines are monitored for depressed voltages and interface flows are reduced to avoid voltage collapse. About 2300 MVArs of shunt capacitors were added in the PJM system and parts of ECAR recently,. so that the need to invoke RCP constraints has lessened. A major 765 kV line across the Blue Ridge mountains west of Roanoke is delayed thus raising questions about the local area reliabiity in the future. American Electric Power (AEP) is planning to build a high-capacity 138 kV line near the Kentucky - West Virginia border, equipped with a UPFC. The intended use of this special facility is to force power onto the new line thus avoiding overloads and voltage collapse in the nearby 138 kV system following the loss of critical 765 kV transmission facilities.

MAAC - Mid-Atlantic Area Council

The MAAC area corresponds to that area served by the Pennsylvania-Jersey-Maryland pool. The transmission system consists of a 500 kV backbone oriented west to east across Pennsylvania and along the coast plus 345 kV interconnections with south-central New York State (NPCC area). The majority of the load is in the coastal urban areas and the major generation sources are in western Pennsylvania and in the ECAR region. Transfers across the 500 kV system are constrained to avoid potential voltage collapse problems in that system and the adjacent 500 kV system in eastern part of ECAR. The RCP discussed above restricts flows in MAAC to prevent voltage collapse in MAAC and ECAR facilities.

For the reasons discussed above, the backbone transmission system is inadequate to fully exploit the potential economy purchases from systems to the west of Pennsylvania or full utilization of western-MAAC generating resources. Never-the-less, no major transmission additions are anticipated before 2005. Recent attempts to build a 500 kV line across the northern part of Pennsylvania were blocked on the basis of EMF fears, land-use concerns, and lengthy debate over the projected economics of the project. A plan in 1971 to build a 765 kV line across northern Pennsylvania was abandoned due to a lack of financial backing. In the early 80's, an order was placed for an HVDC cable across Lake Erie to import power from Ontario and deliver it across Pennsylvania to the coastal urban load centers. The work was canceled during the contractor's early design stages because less expensive power from the Midwestern US sources was found.

As mentioned above, the recent addition of 2300 MVArs of shunt capacitors on the 500 kV system provided increased capacity. The studies that proved the effectiveness of the shunt capacitors also considered the use of conventional series compensation instead. The series compensation alternative would have provided more security margin against voltage collapse but was more expensive than the shunt capacitor approach. Concerns for subsynchronous resonance (SSR) and a lack of consensus on who would pay for the upgrade versus who would benefit, also influenced that choice. The series capacitor option is still available for the next enhancement, and the use of TCSC could allay the SSR concerns.

NPCC - Northeast Power Coordinating Council

The NPCC area consists of utilities serving New York State, the six New England states, Ontario, Quebec and the Maritime Provinces of Canada. The transmission systems in New York (NY) and New England (NE) are 345 kV and 230 kV with one operating 765 kV line in NY. The Ontario Hydro system is largely 345 kV with some 500 kV and Hydro Quebec is composed of 735 kV with a 3 15 kV underlying network.

Very little new transmission is anticipated in NPCC systems before the year 2005. A second 345 kV line between New Brunswick and Maine, about 230 km in length, is planned. Hydro Quebec is planning extensions of its 735 kV system near the US border. West to east flows on the 345 kV system in NY are restricted due to stability and voltage collapse considerations. The imports from Quebec into NY and NE are limited as a consequence. Those import restrictions are due, in part, to concerns for voltage collapse in Kentucky (see reference to RCP under ECAR) , thus illustrating how interdependent the eastern US network systems have become.

New transmission ROW in NY and NE will meet with substantial resistance due to public concerns over environmental and land-use concerns. Hydro Quebec is completing a major investment in their transmission system to increase their reliability to meet NPCC reliability criteria. However, short term opportunities for increased imports from Hydro Quebec are now minimized by a combination of inadequate Quebec and US transmission facilities, the short-term overcapacity in NY and NE, and the uncertainties associated with regulatory reforms. Hydro Quebec is interconnected to NPCC-US via three HVDC projects; to NY via Chateauguay (1000 MW), to Vermont via Highgate (200 MW), and Massachusetts via HQ-NE Phase II (2000 MW). The Eel River (320 MW) and Madawaska (350 MW) back to back links connect HQ and New Brunswick. The power imported over the 2000 MW Phase II project is limited to approximately 1500 MW much of the time by stability constraints in New York, PJM (MAAC) and ECAR.

Recently Hydro Quebec canceled 1450 MW of long term sales and has deferred new generating capacity, including the "Great Whale" project in their Hudson Bay region, due to lower-than-projected internal load growth and reduced export opportunities. Eventually, probably within the 25 year period of interest in this research, the need for additional transmission capacity within NPCC-US and between the US and Canada portions of NPCC will arise.

SERC - Southeastern Electric Reliability Council

The RDI report [RDI] observes that several SERC members have experienced double digit load growths in the recent past. New and relocating industries are finding economic reasons to settle in the southeastern states. The population of Florida is still rising and demand for electrical energy is likely to grow at about 2.5% annually over the next decade. The region expects to add about 2800 km of new transmission at 230 kV and above. Most of this will be intra-system reinforcements of 230 kV. Florida plans two 500 kV additions, totaling 155 km. Over 50 small projects involving 700 km of lower voltage lines are also planned in Florida. Those utilities serving Georgia, Alabama and parts of Louisiana and the Florida panhandle plan numerous 230 kV additions plus three short 500 kV additions (longest is 108 km). TVA anticipates a 200 km 500 kV line across the western half of Tennessee, and a 60 km 500 kV link with Kentucky Utilities. About 25 short 230 kV projects and three 500 kV lines are to be added in Virginia and the Carolinas. The longest lime is 175 km of 500 kV to be added by AEP.

There is 1600 MW of FCITC (frrst-contingency-interchange-transfer-capacity) available for ECAR to transmit excess capacity to SERC, should the need arise. The wide area covered by SERC, representing future growth in energy demand, varied weather zones and two time zones, should offer future opportunities for economy interchanges.

MAIN - Mid-America Interpool Network

MAIN consists of a thin slice of the middle US including three large metropolitan areas; Chicago, Milwaukee, and St. Louis. The region. will enjoy a large capacity margin (18-22%) through the year 2004 and plans little additional transmission plant in the next decade. The largest of 6 planned 345 kV projects involves 70 km of new line and the energization of 120 km of existing 345 kV line operated at 138 kV now. Some localized concerns for potential voltage collapse under contingency conditions have been mitigated in the past.

The 345 kV backbone paralleling the west shore of Lake Michigan could be the target of power marketers seeking to import excess capacity from Ontario for sales within MAIN or elsewhere should the opportunities arise. Relatively short HVDC submarine cables across the lake may be required, but none are contemplated at this time.

Mapp - Mid-continent Area Power Pool

MAPP member utilities serve an area including the states of North and South Dakota, Minnesota, Nebraska, Iowa and parts of Illinois, Michigan Wisconsin and Montana. The Canadian Provinces of Manitoba and Saskatchewan are also included. This area is largely rural except for the metropolitan regions of Minneapolis, Minnesota, Omaha, Nebraska and Winnipeg in Manitoba. Most of the generation is remote from the major load centers. MAPP contains four HVDC lines including Square Butte (Minnesota P&L), CU (United Power Assoc.), Nelson River bipoles 1 and 2 (Manitoba Hydro), plus two back to back HVDC links to WSCC at Miles City Montana (western Area Power Admin.) and the David A. Hamil link at Stegall, Nebraska.

MAPP members reported to NERC that, including yet-unspecified short-lead-time generation additions, the area will maintain 15% reserves through 2004. MAPP-US members plan very little new bulk power transmission in the decade to come. Of the 60 plus planned projects, only six involve 345 kV additions; the longest being 172 km from Pauline to Moore in Nebraska. The remainder of the projects are 230 kV and below. The existing transmission will be heavily utilized and some localized low voltage problems are likely during contingencies. North to South transfer paths will probably encounter limitations, thereby requiring yet undefined mitigation.

SPP - South West Power Pool

SPP covers the states of Kansas, Oklahoma, Arkansas, Louisiana, and portions of Mississippi, Missouri, Texas and New Mexico. Bulk power transmission is 500 kV in Louisiana and Arkansas and 345 kV and 230 kV elsewhere. SPP has two back to back HVDC links to ERCOT; Oklaunion (200 MW) and the recently commissioned 600 MW back to back link connecting to ERCOT at Welsh - Monticello. The Eddy County (200 MW) and Blackwater (200 MW) back to back systems link SPP with WSCC in eastern New Mexico. A third interconnection to WSCC is under consideration as part of the merger of Public Service of Colorado (PSC) and South West Public Service (SPS).

The NERC report indicated that generation reserves in SPP could bottom out at the minimum allowed 13% by the end of the decade. An increased reliance on gas-fired generation is anticipated. No major transmission lines are planned. About 190 km of the 900 km of new lines will be 345 kV, the longest beiig 60 km. The remainder are 230 kV, ranging in length from 17 km to 200 km. The intertie between merging companies PSC and SPS is expected to include a back to back link. Very limited exchanges-of power exist between SPP members and members of ERCOT and WSCC. Future FERC pressures toward open access coupled with locally divergent generation costs could change that situation. With about one half of the SPP boundary being adjacent to currently-asynchronous networks, the likelihood exists that more back to back HVDC links may become beneficial.

ERCOT - Electric Reliability Council Of Texas

The ERCOT system, covering most of Texas, operates asynchronous from the remainder of the US. The transmission backbone is a 345 kV network linking the major cities of Dallas/Fort Worth , Houston, Austin and San Antonio in the east-central section of Texas. The 345 kV system reaches west from Dallas to Abilene and Odessa and south down the gulf coast from Houston to Corpus Christi and Brownsville. A very extensive underlying system of 138 kV and 69 kV lines compliments the 345 kV network. About 420 km of new 345 kV is planned. The longest line included is a 225 km line from the Lon Hill substation in the Corpus Christi area to the Edinburg substation west of Brownsville. That line will constitute a third "trunk line" into the south coastal area. A tentative back to back intertie with Mexico is shown on'the map provided in the ERCOT OE-411 report, but no rating is indicated.

The new Twin Oaks plant south of Dallas will require a 118 km double circuit 345 kV line into the 345 kV ring around Dallas. Besides that case, few large (over 400 MW) new generating sources are contemplated. The generation is generally located close to the load, so the 345 kV lines are not routinely utilized to their limits. Most new generation will be peaking capacity, operating only a few hours a day, so transmission alternatives are difficult to justify. No transmission bottlenecks exist within ERCOT and none are anticipated for the next decade.

The differences in lambdas between ERCOT and adjoining systems are not very large (<$5/MWhr) so economy exchanges may not pay for large transmission investments. If ERCOT utilities or developers wish to exploit open access policies, some high industrial rates in nearby New Mexico may provide opportunities for direct energy sales outside of ERCOT. Selling to Public Service of New Mexico or El Paso Electric for resale to those industrials is not as attractive, since those utilities already have access to inexpensive energy from SPP and elsewhere.

WSCC - Western States Coordinating Council

The WSCC area covers most of the 'western states" plus Alberta and British Columbia in Canada. It is characterized by long lines and remote generation. The part of the system in the US has been likened to a "doughnut" in shape. The western side of the doughnut runs from the Canadian border to southern California consisting of a 500 kV and 230 kV backbone with liberal amounts of series compensation in the 500 kV lines. The eastern side from Idaho, through Utah and Colorado into Arizona and New Mexico is 345 kV and 230 kV. Paralleling the ac lines in the western side there is a large capacity HVDC line. It runs from the Celilo HVDC converter terminal on the north-central Oregon border to the Sylmar converter terminal north of Los Angeles. The Intermountain Power Project (IPP) HVDC line into north-east Los Angeles imports power from a mine-mouth plant in central Utah. The Miles City, David A. Hamil, Virginia Smith (Sydney, NB), Blackwater and Eddy Co. back to back links tie the eastern "fringes" of the WSCC system to MAPP and SPP.

The generation mix ranges from large hydro plants in the northwest to large coal plants in the desert south west and plains of Montana and Wyoming. Numerous gas-fired and biomass plants have proliferated in California since Public Utility Regulatory Power Act was passed. Some geothermal and wind farms dot the mountains of California, but the WSCC is largely a coal fired system.

On the basis of circuit-miles of new transmission, WSCC will be active in the next decade. Over 9,000 km of new transmission from 230 kV and up will be added or upgraded. Being only a 5% increase in total circuit miles, it doesn't sound like much. However, many of those new circuit-miles are individual lines exceeding 200 km. In addition, the map in the WSCC OE-411 report shows another possible (beyond 2004) HVDC line from northern Oregon (near Celilo at The Dalles) to southern Nevada (near Las Vegas). The 836 km South West Inter-tie Project (SWIP) is included in the total 9,000 km figure. That will be a series compensated 500 kV line from southern Idaho into the Las Vegas area with a 200 km tap into Delta Utah, near the northern end of the IPP HVDC lime. An additional 500 kV ac line from Delta Utah into Las Vegas is shown for the year 2000.

Some of the planned ac lines may be more expensive than HVDC if the cost of HVDC converters decreases substantially. However, multi terminal HVDC would be needed in several cases. This was borne out by the earlier study [Clark, 1992] that sought an estimate of HVDC transmission opportunities. Because of the great distances involved in the western states, reduced-cost HVDC should be competitive with conventional or FACTS enhanced ac alternatives.

ASCC - Alaska Systems Coordinating Council

The ASCC officially covers only the Railbelt Utilities, so called because they serve the load areas that developed along the Fairbanks-to-Anchorage railroad. The Railbelt also includes the Kenai peninsula south of Anchorage to Homer on its southern tip. Due to the north-south longitudinal nature of the 138 kV transmission system reliability is a major concern. For example, transmission inadequacy is cited as reasons for a second tie between Anchorage and the Kenai, as it is for a second line planned from the Healy coal-fired plant to Fairbanks. A tie between the currently-isolated Valdez region and the Railbelt is also contemplated.

Other widespread regions of Alaska operate asynchronous due to the distances between them and the relatively small electrical loads involved. The islands of South-east Alaska include four "mini-transmission" systems serving the separate regions of Juneau, Petersburg/Wrangle, Ketchkan, and Sitka. These are 69 kV, 115 kV and 138 kV systems powered by hydro and diesel generators. Because these areas of South-east Alaska are separated by mountains and water, relatively low capacity, forced commutated direct current inter-ties might prove beneficial in the future. Being isolated and spread out, these systems demand generating reserve margins exceeding 30%. If inexpensive HVDC or Low Voltage DC systems, packaged in 10 MW - to - 50 MW modules, could be offered, perhaps more connectivity could become feasible in Alaska.

APPENDMB

FACTS & OTHER AC TECHNOLOGIES THAT COMPETE WITH HVDC

This appendix describes the "ac technologies" mentioned throughout Section 3 and elsewhere in this report. Important capabilities and limitations of each technology are indicated. The transmission technologies discussed can be envisioned in three groupings:

1. Transmission equipment (lines, transformers, etc.) that actually transport power,
2. ancillary equipment that enhance a line's capability to transport power, and
3. auxiliary equipment, when placed in the line, can control the flow of power.

The first category includes conventional three phase ac and unconventional schemes like high phase order transmission, both of which may compete directly with HVDC in providing a means to transport power. The second category includes technologies, such as shunt and series compensation, that do not transport power themselves (except maybe within a substation) but do enable more power to flow over an ac line, reduce losses, or increase reliability. These technologies thus indirectly provide increased transmission capacity efficiency or reliability without new physical transmission capacity. The third category includes such devices as conventional phase shifters which are able to route power flows to better utilize the given transmisssion capacity. Some equipments reside in both categories 2 and 3 and may aleviate stability problems which can otherwise place limits on power transfer. HVDC lines incorporating forced commutated converter technology covers all three categories.

B.1 TRANSMISSION LINE TECHNOLOGIES

B.1.1 Conventional Three-Phase AC Lines

The very first power systems were dc and small remnants of these systems still exist in some places but three-phase ac transmission now forms the, basis for virtually all power systems world-wide. Conventional three-phase ac transmission is an industry standard. It may be three wire or four wire, counting the neutral, and is used in a variety of voltages. In the U.S. most transmission lines are operated at line-to-line voltages of 115kV, 138kV, 169kV, 230kV, 345kV, and 500kV. Lines operated at lower voltages, such as 69kV, 34.5kV, etc. are sometimes classified as sub-transmission or even distribution. Some lines are operated at voltages standard in Europe especially near the borders with Canada where such European standards are followed more readily.

Major advantages that led to the dominance of ac include:

- the ability to transform power to high voltage for efficient transmission and progressively lower voltages for distribution and utilization,
- the ability to easily and safely interrupt current flow on naturally occurring current zeros without producing unacceptably high voltage across inductive elements (Faulted lines and equipment can thus be removed without de-energizing the entire system; large AC grid networks are therefore feasible.),
- the ability to *use* rugged inexpensive motors,
- the ability to meter and relay using inexpensive devices.

The dominance of three phase ac puts other transmission technologies at a disadvantage because they must interface with conventional ac systems. However, to the extent that conventional three phase transmission can be re-engineered in compact line configurations, etc., there is virtue in staying with a well developed and proven technology.

B.1.2 Compact Three Phase Transmission

AC circuit designs for transmission (230 kV and below) are not normally optimized to minimize right-of-way requirements. More compact designs may therefore be used to squeeze extra circuits or higher voltage circuits into existing right-of-ways, or to use new right-of-ways that are smaller than normal.

Substation voltage upgrades also would be required to support line voltage upgrades. There is some experience with substation voltage upgrading [Panek,1992], for substations currently operating at 16 1 kV and below. Upgrades of one BIL step are frequently possible so that a 115 kV substation can operate safely at 230 kV, for example.

B.1.3 UHV Lines

Ultra High Voltage (UHV) transmission involves lines rated at 765 kV are in limited use in the U.S. The higher voltage permits larger power transfers. Significant technical and manufacturing hurdles would need to be overcome to use even higher voltages. The high electric fields produced by UHV lines and their visual impact have deterred their use in most parts of the country. Even those utilities that have 765 kV lines in the U.S. meet with substantial resistance to expansion plans. Hydro Quebec operates their bulk power grid at 735 kV.

B.1.4 High Phase Order Transmission

High phase order transmission involves six phases or twelve phases [Stewart,1993]. Higher power densities and reduced fields are possible compared to conventional three-phase lines. Some double circuit three-phase towers may be converted to six-phase use. To exploit twelve-phase transmission, or to obtain the maximum advantage of six-phase transmission, special tower designs are needed (see Figure B.l). Where voltage conversion is not required for other reasons

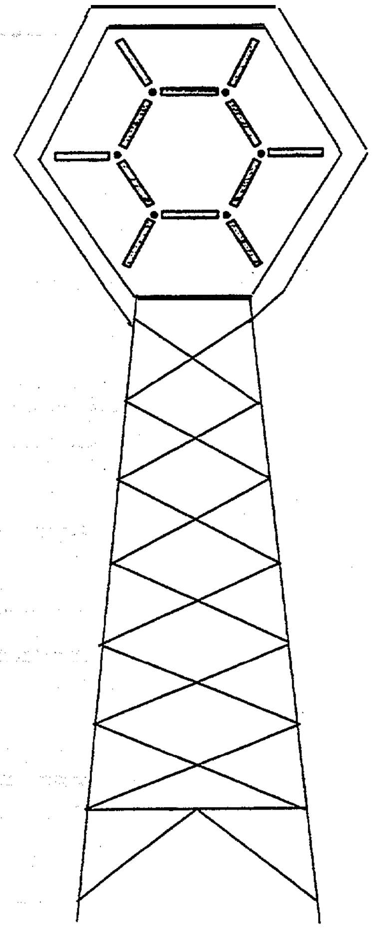


Figure B.l Experimental Tower and Conductor Arrangement For Six Phase Transmission Circuit

extra transformers will be needed to interface high phase transmission to the three-phase system Special transformer designs would be needed for twelve phase transmission.

The incentive for converting to a double circuit 3 phase line to six phase lies in the 50% reduction of line impedance that results. However, the extra transformers required to interface with existing three phase systems introduce extra impedance that tends to offset that reduction in line impedance. A break-even distance of about 20 miles (30 km) is typical wherein the added transformer impedance ballances the line reactance decrease.

B.2 REACTIVE COMPENSATIONFORINCREASED TRANSMISSION CAPABILITY

Reactive power compensation schemes are employed to achieve maximum utilization of the transmission lines for transporting active power. Both capacitive and inductive compensation means are used where appropriate. They are connected in series and in shunt arrangements. When employed with static switches (thyristors are most common although gate-turnoff - GTO - devices are emerging) the compensation is rapidly variable, as is necessary to improve stability.

B.2.1 Fixed and Mechanically Switched Shunt Compensation

Voltage normally increases when a shunt capacitor is connected and decreases when a shunt reactor is connected. Shunt compensation can thus provide valuable voltage control. If the compensation is switched it can also improve voltage regulation (the change in voltage over the course of the day due to loading cycles, etc.). However, fixed shunt capacitors actually degrade voltage regulation. The reactive power provided by fixed shunt compensation varies as the square of voltage so a fixed shunt capacitor provides fewer vars when voltage is iow just when more vars are needed to support voltage. Conversely, it provides more vars when voltage is high and can aggravate an over-voltage problem. Never-the-less, with a good undersatnding of these characteristics, they can be employed to the system operators' advantage.

Strategically placed shunt compensation can also reduce losses by decreasing the reactive component of current flowing in the lines. A corresponding decrease in I^2R and I^2X losses result. Shunt capacitors are commonly used on distribution systems for increasing the power factor of the "load" as seen by the transmission network. Shunt reactors are frequently required on high voltage transmission lines for surge protection (may become less common with modem arrester technolgy) and for absorbing the excess charging currents during light line loading. They may be switched or unswitched. These devices will continue to be employed for maintaining steady state voltages within prescribed tolerances during operation of ac transmission.

Strategically placed fixed or switched shunt capacitors also may help improve rotor angle or voltage stability. However, if they are placed in the wrong location it may actually degrade rotor angle and voltage stability. To the extent shunt capacitors are effective for improving stability without causing unwanted side effects, fixed and switched shunt capacitors and reactors will continue to be used because they are inexpensive. However, compared with series capacitors, shunt capacitors are less effective for stability improvement in most cases.

If used at transmission voltages for transient stability improvement, shunt capacitors would need to be switched on - off - on, etc., in rapid successesion, in order to be most effective. However, when a shunt capacitor is switched off it will retain a trapped charge which can add to line voltage if switched on again soon after being de-energized. The combined voltage build-up can reach damaging levels for switching mechanisms and the capacitors themselves. Standard capacitors are designed with discharge resistors for dissipating the residual voltage in about 5 minutes. Unless equipped with fast-discharge circuitry, mechanically switched capacitors can not be reconnected shortly after they are disconnected. The static var compensator, discussed next, is ideal for such repeated, rapid switching duty.

B.2.2 Static Var Compensators (SVC)

Static var compensators (also called static var controllers by some) have become increasingly common. SVC's provide all the benefits of fixed and mechanically switched shunt compensation plus the added benefits of fast controllability, Figure B.2 is a one line diagram for a typical SVC. Thyristor controlled reactors (TCR's), thyristor switched reactors (TSR's) and thyristor switched capacitors (TSC's) may be used separately or in combination for a SVC. Filters and fixed or mechanically switched shunt capacitors and reactors may also be included. Thyristor controlled reactors have a continuous response but also produce harmonic currents. Harmonic filters are normally needed with TCR's. Thyristor switched reactors and capacitors are switched in such a way as to 'not produce harmonics. The timing for switching TSC's is chosen so the trapped charge does not buildup for repeated switching. (See discussion of mechanically switched shunt compensation above.) Therefore, there is no practical limitation on repeated switching of TSC's.

SVC control can be used to correct voltage stability and voltage regulation problems. Strategically placed and properly controlled SVC's may also improve power system rotor angle (transient and dynamic) stability. Most of the SVC's employed today were implemented for dynamic voltage regulation or stability improvement for which switched shunt capacitors and reactors are unsuitable. Because they are considerably more expensive than switched capacitors and reactors, SVC's are employed only when their inherent high speed of response and their ability to vary the amount of compensation continuosly cannot be provided by the less expensive devices.

Functionally, the SVC becomes a fixed shunt admittance if its controller demands maximum or minimum vars. Any improvement to dynamic (oscillatory) stability which continuous control provides ceases at the limits and a possibly stable situation may revert to an unstable one. However, the act of going to its capacitive limit quickly during the first rotor-angle (forward) swing can be sufficient to preserve transient stability. Provided the voltage partially self corrects upon subsequent rotor angle swings (oscillations), the SVC should return within its regulation range and work to preserve steady state stability.

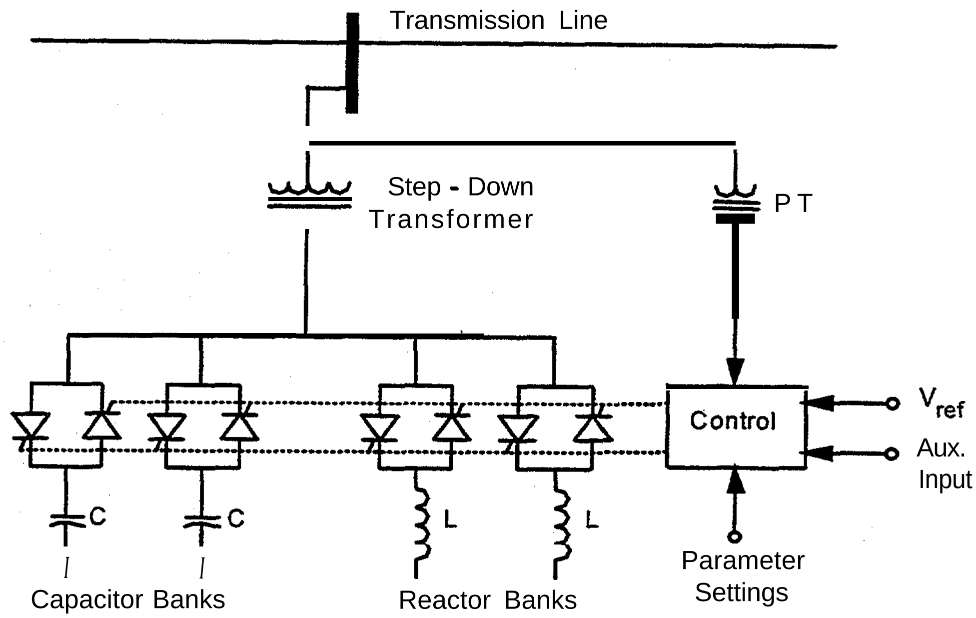


Figure 8.2 - Conventional Static Var Compensator (SVC) shown with thyristor switched capacitors and either thyristor switched or phase controlled reactor branches. If phase controlled, then harmonic filters would also be required.

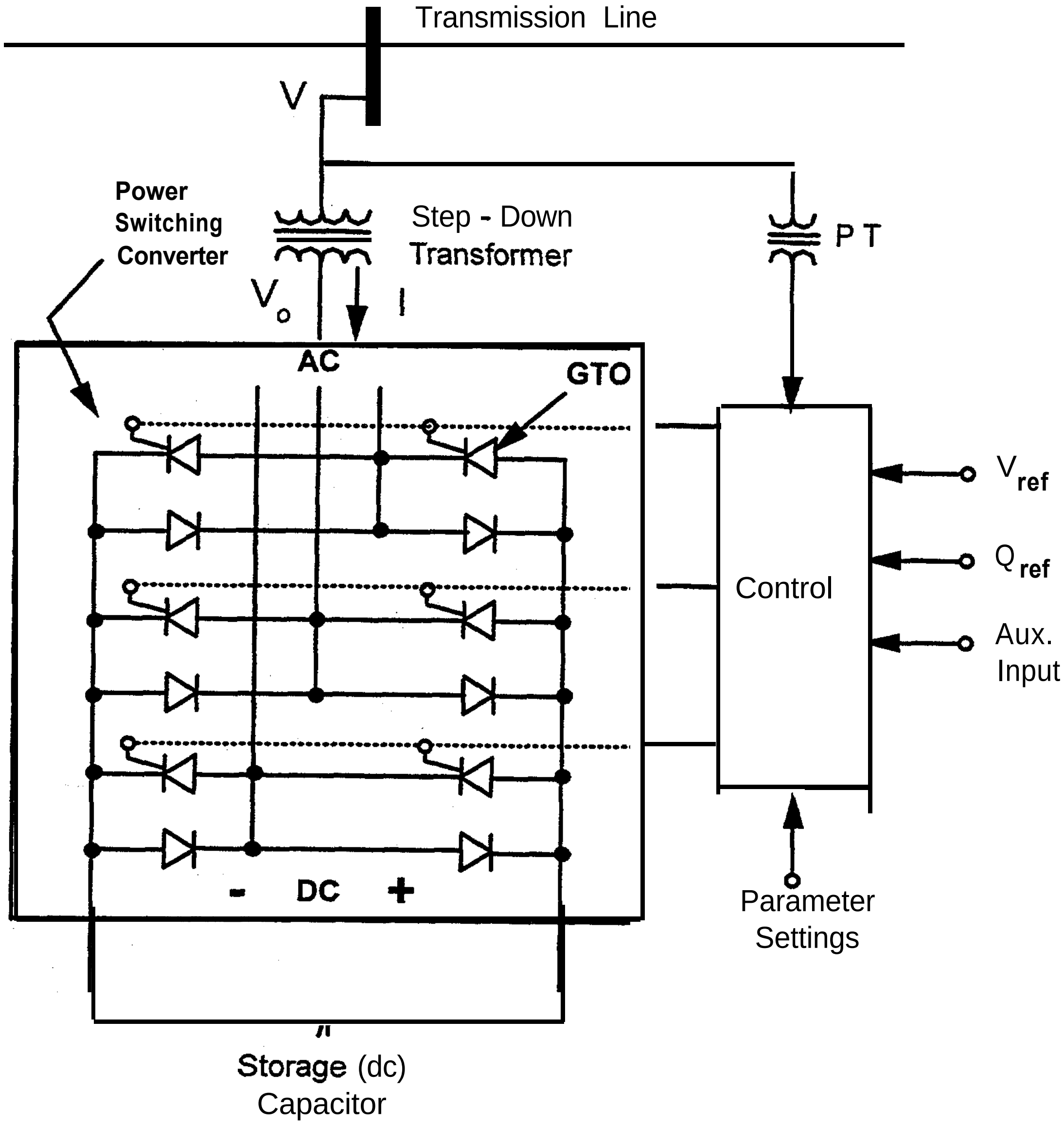
SVC's are in service in many US systems and the technology is mature. They will be used in the future for the same reasons they are in use today. However, there are limitations to their performance benefits. The fall off of voltage support when pushed to its capacitive limit described above is one such limit. When applied at places in the system where the short circuit duty becomes low following contingencies (just when the SVC is neded most) the SVC capacitors can interract with the system to cause a low order resonance condition, say at 2nd or 3rd harmonic of the power frequency. This can cause the SVC's voltage regulator to go unstable and cause undesirable variations of its var injection. Finally, the high bandwidth voltage regulator can also destabilize small high frequency variations in voltage caused by torsional oscillations of turbine generator shafts in nearby thermal power plants. To avoid such interractions, the SVC controls must be retuned in such a way that they are made less responsive for transmission'system disturbances they are meant to mitigate. If the drop in voltage support under depressed voltage conditions is critical, then the STATCOM, described next is recommended. Otherwise, most transmission system applications requiring rapidly adjusted var supplyor absorption is satisfied by the SVC.

B.2.3 STATCOM

Where robust var contribution is required at depressed voltages, the STATic COMpensator or STATCOM is now available. The STATCOM employs voltage source converter technology to generate or absorb reactive power at the point of application in the system. The voltage source is a dc storage capacitor on the dc side of the converter. Being a voltage source device, it behaves in the short term like a synchronous condenser. Its initial name was STATCON for static condenser because of this observation. In contrast to this, an SVC is a current source, the current from which depends upon the applied line side voltage.

Figure B.3 is an electrical diagram for a STATCOM developed by Westinghouse and EPRI. This device uses GTO's and operates to either absorb or supply vars to the AC system. The maximum and minimum var output would depend upon its maximum current rating. As illustrated in Figure B.4, its output capability would be slightly improved compared to an SVC, but can be applied for the same reasons SVCs are currently employed. The overall in-service losses of a STATCOM using GTO's will exceed those of an SVC that employs TSC's. Currently, GTO-based STATCOMs incur active power (KW) losses equal to about 2% of the STATCOMs reactive power rating (KVAR). This is approximately double the losses of a typical thyristor switched capacitor style SVC. In time, STATCOM's using lower loss circuitry will be available so the comparison with SVC's will converge.

STATCOMs can provide dynamic voltage support for voltage and rotor angle stability in transmission applications, similar to the SVC. They will be used for new ac lines and reinforcement of existing systems. Because the STATCOM converter technology and VSC HVDC are similar, it is likely that STATCOMs could be integrated with future HVDC projects as extensions of the reactive supply subsystem of the HVDC converters.



If $V_0 = V$ then $I = 0$

If $V_o > V$ then I is Capacitive

If $V_o < V$ then I is Inductive

Figure B.3 - STATCOM (Static Compensator) Device Elements

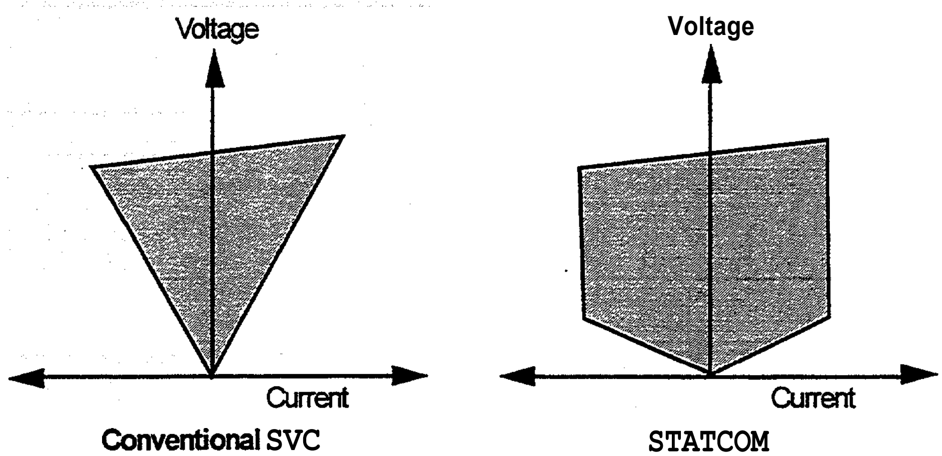


Figure B.4 Comparison of SVC and STATCOM Current - vs - Voltage Relationships

B.2.4 Series Capacitors - Fixed and Mechanically Switched

The use of series capacitors in ac lines is a mature and very cost-effective approach to accommodate large, yet stable power flow on long lines. They are commonly used on the 500 kV systems in the western U.S. and were recently added to 735kV lines in Quebec. There is a risk of sub-synchronous resonance (SSR) in cases where the lines connect to steam turbine generators. The abrupt change in generator shaft torque (impact torque) caused by the inception and clearing of a fault may also be increased by series capacitors. To avoid serious SSR and shaft impact torque problems, including (in the extreme) damage to turbine shafts, the amount of series capacitance must be limited.

Series capacitors improve transient and dynamic rotor angle stability. They also improve voltage stability. The var output from series capacitors increases as line loading increases. This is a major advantage, improving voltage regulation since more vars are needed for voltage support when lines are heavily loaded.

Conventional (mechanically switched) series capacitors are a very cost-effective means of increasing the transmission line's stable transfer capability, provided the line is a so-called long line for which the loadability islimited by stability. Typically, such lines are limitted to SIL or slightly greater by synchronous or voltage stability factors. They are not as effective in short line or tight network situations. In network situations they are somewhat effective in forcing lower voltage lines (higher impedance paths that can benefit from series capacitors) to share load with higher voltage parallel lines. The PAR and UPFC probably will be more versatile in such cases, especially if the lines involved are "short".

B.2.5 Thyristor Switched and Thyristor Controlled Series Compensation

Figure B.5 shows two schemes for controlling series compensation using thyristors. The upper figure employs thyristors to rapidly and repeatedly switch the series capacitors in and out of the power flow path. This is often called a TSSC for thyristor switched series capacitor. The lower part of the figure shows a thyristor controlled reactor in parallel with a portion of the series capacitors which acts to vary the voltage across the capacitor C in such a way as to make it appear as though its reactance is varying. This latter approach is termed a thyristor controlled Series capacitor or TCSC.

Such controllable series compensation can provide the benefits of fixed series compensation plus the ability to vary the active power that they and other series connected devices and the line conduct. The power control of the TCSC can be achieved quickly so it may be used to modulate power to improve dynamic stability. It could also be used to improve transient stability or for steady-state power flow control to satisfy the terms of a wheeling contract, for instance. The TSSC is effective in improving transient stability and can also regulate the steady state power flow over a limited range. If only steady state flow control is required, thyristors probably would not be needed since mechanical switches should suffice.

TSSC and TCSC approaches are good for long line situations where fast changing compensation is required for stability purposes. The TCSC may also be used in network or short line cases if series capacitors are needed but SSR is a threat. The TCSC with SSR control prevents a series resonance condition between capacitors and the system inductance in series with the capacitors from ever stsrting. They may have a second order influence on SSR problems caused by other series compensated lines in the system, but only by chance.

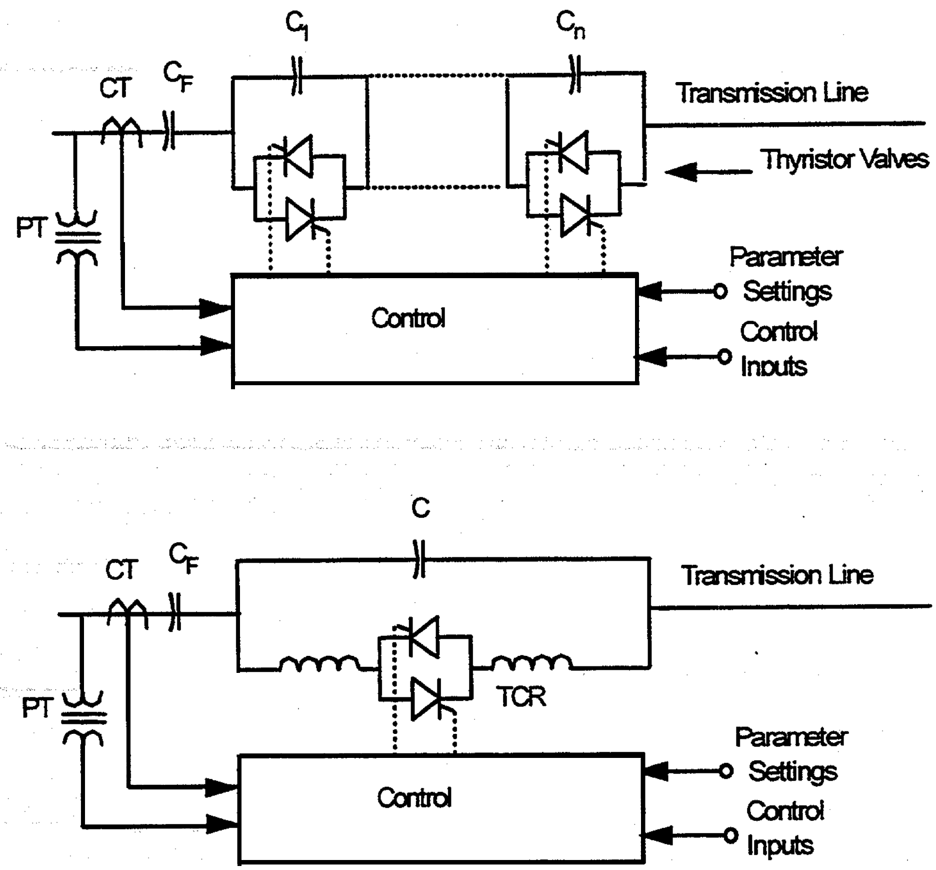


Figure B.5 Controllable Series Compensation
Discrete capacitor switching (top)
Continuous control with TCR (bottom)

B.3 POWER FLOW CONTROL DEVICES EMPLOYING PHASE ANGLE REGULATION

The equipment described in this section provide control of active power flow in the line in which they are connected by adjusting the phase angle across the device. Some of them also provide adjustable reactive power to regulate voltage magnitude simmultaneously.

B.3.1 Phase Angle Regulating Transformers (PAR)

Phase angle regulating -- PAR -- transformers (also called power shifting transformers) are used at strategic locations where power flow control is needed. They are effective in regulating steady state tie line power flows to comply with contract power transfers between companies.

The transformer creates a voltage angle phase difference between its primary and secondary terminals. Phase shifts of $\pm 30^\circ$ are typical and higher phase shift ranges can be achieved by placing PARs in tandem. The shift may be fixed or adjustable under load. The phase shift is changed by adjusting transformer taps. The phase shift changes are thus relatively slow and incremental rather than continuous.

The leakage reactance of phase shifting transformers varies with the phase shift angle. It is quite large for high angles so this can be a disadvantage in some applications. Phase shifting transformers are more expensive than conventional transformers and only a few suppliers offer them. The cost of a PAR is roughly proportional to the phase shift range required.

Phase shifters control the power flow through themselves (and other series connected equipment) by changing the angle between the primary supply voltage and the voltage on the line-side of the series (boost/buck) winding as illustrated in Figure B.6. The series boost/buck voltage' is generally in quadrature with the primary supply voltage. Care must be taken to prevent excess line-side voltage that might result as the boost voltage is added to the supply-side voltage. Special winding schemes can be devised to minimize this problem, but common schemes must limit the maximum angle insertion to avoid too high or too low line-side voltages.

A change in voltage angle will produce a permanent change in power flow only if a parallel transmission path exists. They cannot control power flow between otherwise isolated systems or in radial circuits.

Conventional PAR's will continue to be applied where steady state power flow control is desired. They are a mature technology, and are cost-effective where a limited range "flow valve" is needed. Back-to-back HVDC is it's nearest functional equivalent in current technology, but cannot compete with the cost of a PAR if only steady state control over limited range is required. New technology approaches to the flow-control problem like the TCPAR described next and those that use voltage source converters (UPFC, SSSC) will perform the same function as the PAR, with the added ability for rapid adjustments compared to the conventional PAR.

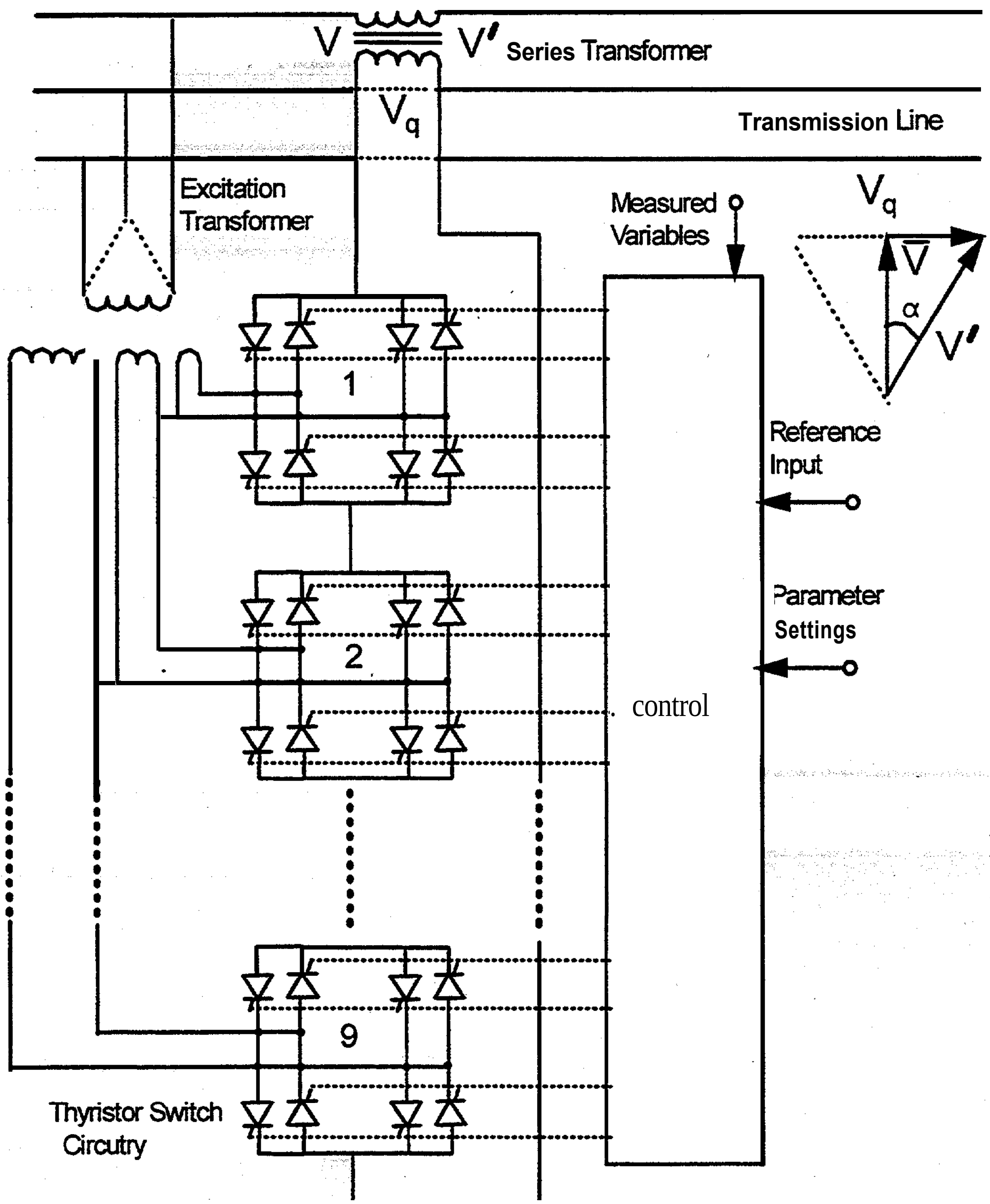


Figure B.6 Thyristor Switched Power Angle Regulating (PAR) Transformer

B.3.2 Thyristor Controlled Phase Angle Regulators (TCPAR)

One extension to the conventional PAR transformer is the TCPAR. Thyristors are used instead of (or in addition to) mechanical taps to accomplish rapid phase angle adjustments. Studies have shown that discrete switching of the winding taps - as opposed to continuous conduction via thristors) is adequate for most functional needs for rapid adjustment. For practical purposes the TCPAR could be called a TSPAR to reflect the discrete switching. Figure B.6 is a circuit diagram for a TSPAR -thyristor *switched* phase angle regulator. Depending on which thyristor conducts the voltage Vq will link all, some, or none of the turns of the excitation transformer. The level of phase shift which depends upon the voltage Vq is thereby controllable. For this circuit arrangement the amount of phase shift is limited to less than ± 90°. Other circuit arrangements might permit a 360" phase shifting range.

Thyristor switched phase angle regulators might provide the benefits of conventional phase shifting transformers plus smaller phase shifting increments, rapid control, and lower maintenance. Rapid control can help improve transient or dynamic rotor angle stability as was demonstrated in a study of the East of River interface in Arizona [EPRI EL-6943V2]]. A study [EPRI TR-1039041 of the application of a TCPAR near International Falls, Minnesota showed that the stability of the Ontario - Minnesota transmission interface could be improved substancially. In that case a hybrid combination of two conventional PARs in series plus a TCPAR was studied. Each of the conventional PARs were capable off 70 degrees (for ± 140 degrees total) to provide steady state control range. The TCPAR provided an additional dynamic adjustment to maintain transient stability. The study showed that a dynamic range of about ± 12 degrees was adequate for stabilizing the interface under the contingencies considered.

TCPAR's may find limited aplication for situations similar to those referred to above. The UPFC and a derivative called the Static Series Synchronous Compesator (SSSC) [Gyugi,1996], will compete with the TCPAR for applications in relatively tight network situations. For long line applications, some will argue that the TCSC and the Interphase Power Controller (IPC) could provide a more cost-effective approach.

B.3.3 Unified Power Flow Controller (UPFC) and Static Series Synchronous Control (SSSC)

The UPFC is a voltage source converter based system that can provide four quadrant control of power. That is it can vary the active power through it over a wide range, including reversal depending upon the rating of the series winding (buck/boost) and its associated converter. Figure B.7 is an electrical diagram for one form of unified power flow controller that is currently under development. It will employ two GTO based dc bridges one attached to the ac system by a shunt connected transformer and the other attached across a series connected transformer. Both bridges would be connected to the same capacitor on the dc side.

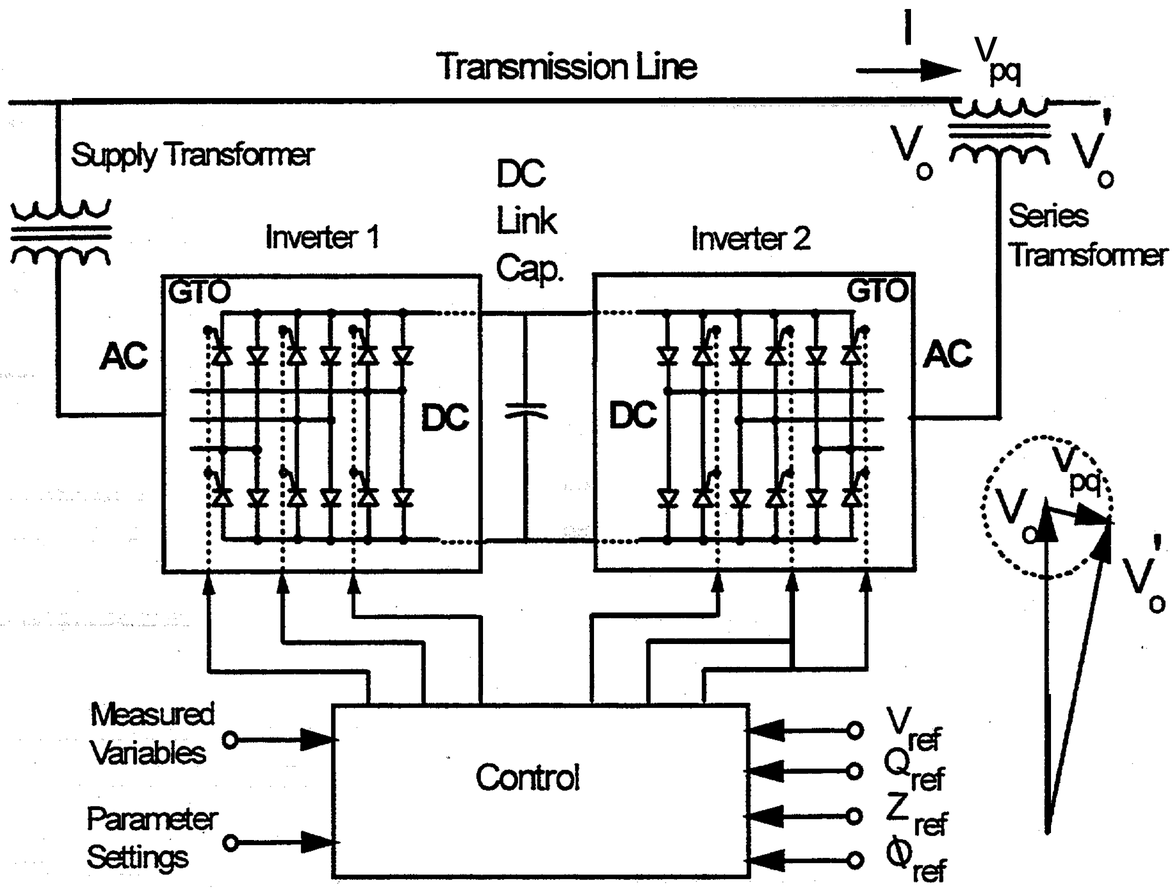


Figure B.7 Unified Power Flow Controller (UPFC)

The bridges could be independently controlled to supply or take vars from the ac system. Any active power taken from the ac system by one bridge would of course by given back to the ac system by the other, less device losses, of course. The voltage across the series connected transformer is controlled to boost or buck voltage and to phase shift the voltage in either direction.

If the series transformer and its associated bridge (inverter 2 - Figure B.7) is removed, what remains is a STATCOM. If the shunt connected winding at the left of the figure and its associated bridge is removed, what remains is the SSSC (static series synchronous compensator) which can provide a limited amount of active power flow control.

The full-featured UPFC with both windings and bridges would have approximately the same capabilities as a thyristor switched phase angle regulator combined with a static var compensator. American Electric Power Co. plans to implement a UPFC [Mehraban,1996; Rahman,1996] in a high capacity line to exercise dramatic power flow control measures aimed at preventing post-contingency overloads and voltage collapse in a portion of their system.

A generic comparative analysis between the UPFC, SSSC, TCSC, TCPAR and back-to-back dc is provided in Section 3.4 of this report.

B.3.4 Interphase Power Controller (IPC)

The IPC is a device being developed by CITEQ [Lemay,1996] that will maintain virtually constant power through the line in which it is installed, without reliance on active control. Through a novel combination of capacitors and reactors and cross phase coupling of voltages via transformer windings, the IPC provides a constant power characteristic over a specific range of system conditions without active control. Mechanical switching of the otherwise passive devices will adjust the steady state power "set point". Figure B.8 illustrates one configuration of the IPC. Future IPC designs could incorporate power electronics to provide fast adjustments for stability enhancement.

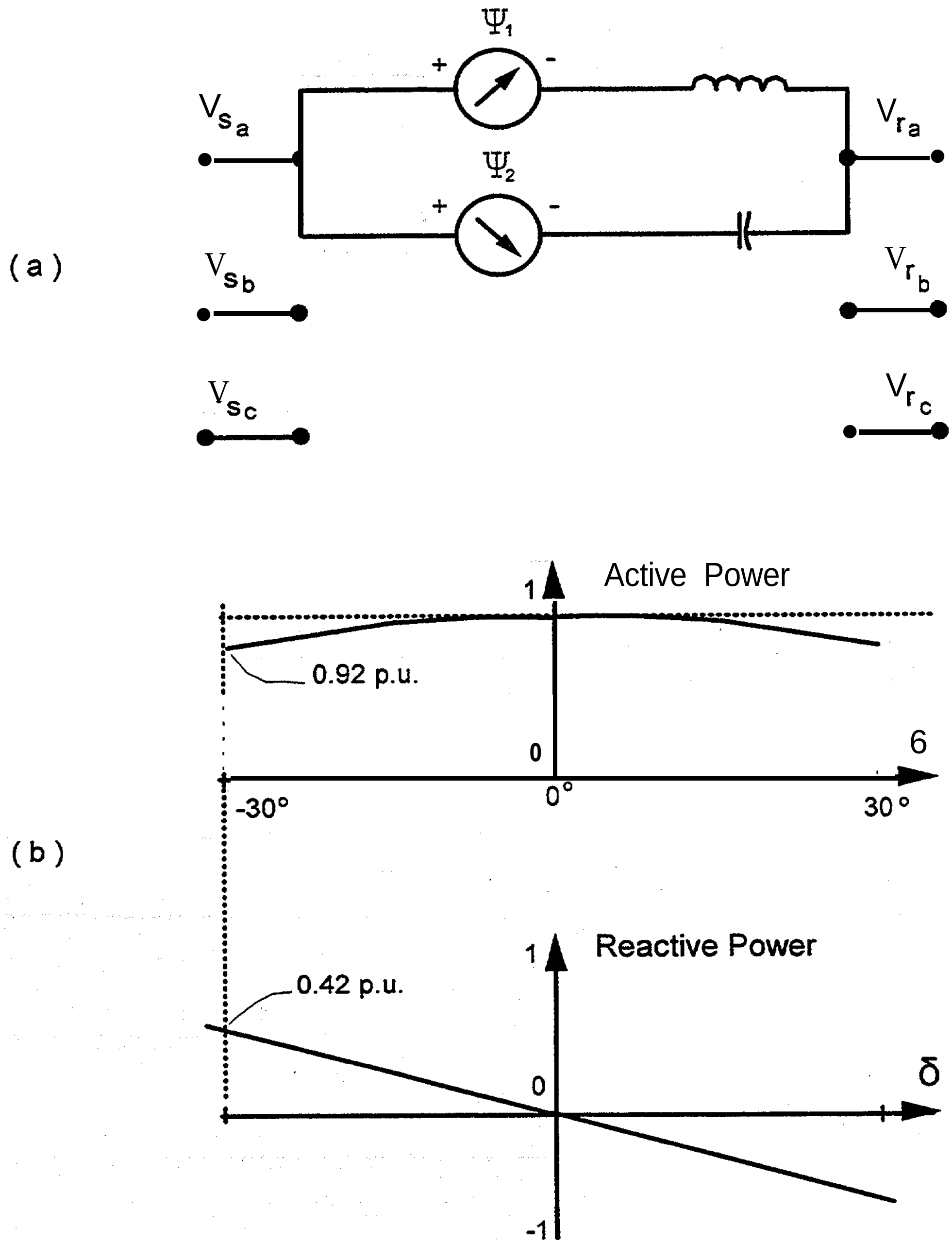


Figure B.8 - The Interphase Power Controller (IPC)
(a) Equivalent Circuit for IPC
(b) Sample characteristics [IEEE, 1996]

B.4 References

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APPENDIX C

DERIVATION OF EQUATIONS FOR UPFC AND SSSC USED IN SECTION 3.4

This appendix contains derivations of the equations used in Section 3.4 to illustrate the power control capabilities of various FACTS and conventional transmission devices. The equations were "programmed" into Excel from which the plots of P vs Q were made. The terminology is defined in Figures 3.4 and 3.5, for the most part.

The analysis begins with complex power S_R :

$$S_R = V_R \left(\frac{V_s + V_i - V_R}{Z} \right)^*$$

$$S_R = V_R \, \varepsilon^{j\delta_2} \left[\frac{V_s \varepsilon^{j\delta_1} + V_i \varepsilon^{j(\delta_1 + \rho)} - V_R \varepsilon^{j\delta_2}}{Z \varepsilon^{j\theta}} \right]$$

$$S_R = \frac{V_R V_S}{Z} \varepsilon^{j(\delta_2 - \delta_1 + \theta)} + \frac{V_R V_i}{7} \varepsilon^{j(\delta_2 - \delta_1 - \rho + \theta)} - \frac{V_R^2}{Z}$$

Expanding using Euler's equation and separating real and imaginary terms gives:

$$P_R = \frac{V_R V_S}{Z} \cos(\delta_2 - \delta_1 + \theta) - \frac{V_R^2}{Z} \cos\theta + \frac{V_R V_i}{Z} \cos(\delta_2 - \delta_1 - \rho + \theta)$$

$$Q_R = -\frac{V_R V_S}{Z} \sin(\delta_2 - \delta_1 + \theta) - \frac{V_R^2}{Z} \sin\theta + \frac{V_R V_i}{Z} \sin(\delta_2 - \delta_1 - \rho + \theta)$$

Next set $\theta = 90 - \alpha$ where a = arctan(R/X)

Also note that δ in the figures is same as ($\delta_1 - \delta_2$) here.

$$P_R = -\frac{V_R V_S}{Z}\sin(\delta_2 - \delta_1 - \alpha) - \frac{V_R^2}{Z}\sin\alpha$$

$$+\frac{V_R V_i}{Z}\left[\cos(\delta_2 - \delta_1 - \alpha)\sin\rho - \sin(\delta_2 - \delta_1 - \alpha)\cos\rho\right]$$

$$Q_R = +\frac{V_R V_S}{Z}\cos(\delta_2 - \delta_1 - \alpha) - \frac{V_R^2}{Z}\cos\alpha$$

$$+\frac{V_R V_i}{Z}\left[\cos(\delta_2 - \delta_1 - \alpha)\cos\rho + \sin(\delta_2 - \delta_1 - \alpha)\sin\rho\right]$$

However, the first two terms are P_o and Q_o respectively (that is P and Q for $V_i = 0$) **so:**

$$P_R = P_o + \frac{V_R V_i}{Z}\left[\cos(\delta_2 - \delta_1 - \alpha)\sin\rho - \sin(\delta_2 - \delta_1 - \alpha)\cos\rho\right]$$

and

$$Q_R = Q_o + \frac{V_R V_i}{Z}\left[\cos(\delta_2 - \delta_1 - \alpha)\cos\rho + \sin(\delta_2 - \delta_1 - \alpha)\sin\rho\right]$$

- For the UPFC the magnitude of V_i and the angle ρ (rho) were both varied.
- For the PAR, angle ρ was fixed at 90 degrees and the magnitude of V_i was varied both positive and negative, between limits.
- For the back-to-back DC, the equations in Figure 3.14 were used, with variable gamma, instead of the above equations.
- For series capacitors, the equations for P_o and Q_o were used with X replaced b X - X , .

- For the SSSC,. the formulation begins back with the complex equation for S_R and continues as shown next.

Begin with:

$$S_R = V_R\left(\frac{V_s + V_i - V_R}{Z}\right)^* = \frac{V_R V_s^*}{Z^*} - \frac{|V_R|^2}{Z^*} + \frac{V_R V_i^*}{Z^*}$$

$$S_R = S_o + \frac{V_R V_i^*}{Z^*}$$

$$S_R = S_o + \frac{V_R V_i^*}{Z^*}, \text{ with } V_i = + j A I, \text{ and } I^* = \frac{S_R}{V_R}$$

$$S_R = S_o - \frac{V_R}{Z^*} j A \frac{S_R}{V_R} = S_o + \left(\varepsilon^{-j\frac{\pi}{2}}\right)\left(\varepsilon^{j\theta}\right)\frac{A}{Z} S_R$$

$$S_R = S_o + \frac{A}{Z}\varepsilon^{-j\alpha} S_R$$

$$P_R + jQ_R = P_o + jQ_o + \left(\cos\alpha - j\sin\alpha\right)\left(P_R + jQ_R\right)$$

$$P_R + jQ_R = P_o + \frac{A\cos\alpha}{Z} P_R + \frac{A\sin\alpha}{Z} Q_R$$
$$+ j\left(Q_o + \frac{A\cos\alpha}{Z} Q_R - \frac{A\sin\alpha}{Z} P_R\right)$$

Grouping real and imaginary components gives:

$$\left(1 - \frac{A\cos\alpha}{Z}\right) P_R - \left(\frac{A\sin\alpha}{Z}\right) Q_R = P_o$$
$$\left(\frac{A\sin\alpha}{Z}\right) P_R + \left(1 - \frac{A\cos\alpha}{Z}\right) Q_R = Q_o$$

which must be solved simultaneously for P_R and Q_R.

The final equations for SSSC are :

$$P_R = \frac{\left(1 - \frac{A\cos\alpha}{Z}\right)P_o + \left(\frac{A\sin\alpha}{Z}\right)Q_o}{\frac{A^2}{Z^2} - 2\frac{A}{Z}\cos\alpha + 1}$$

and

$$Q_R = \frac{-\left(\frac{A\sin\alpha}{Z}\right)P_o + \left(1 - \frac{A\cos\alpha}{Z}\right)Q_o}{\frac{A^2}{Z^2} - 2\frac{A}{Z}\cos\alpha + 1}$$

APPENDIX D

DATA AND RESULTS FOR SECTION 6

This Appendix documents the assumed data and the detailed results for Section 6 entitled " Relative Cost of AC and Hvdc Transmission Options".

D.1 LINE LOSSES FOR AC AND DC ALTERNATIVES

A line loss comparison between I-WAC and HVDC can be made assuming the same power, phase/pole resistance and peak voltage.

Let E = Peak line to ground AC voltage *and* = DC pole voltage magnitude
R = AC phase resistance *and* = DC pole resistance
P = AC 3 phase power *and* = DC bipole power
I_{RMS} = AC RMS current
I_{DC} = DC current

For the 3 phase AC line

$$P = 3\,E/\sqrt{2}\ I_{RMS}$$

and for the HVDC bipole

$$P = 2 * E * I_{DC}$$

Equating the two

$$\frac{3}{\sqrt{2}} E\, I_{RMS} = 2\, E\, I_{DC}$$

$$I_{RMS} = \frac{2\sqrt{2}}{3} I_{DC}$$

$$I_{RMS} = 0.943\, I_{DC}$$

Three phase AC losses are

$$AC\ Losses = 3\ I_{RMS}^{\ 2} R = \left(\frac{2\sqrt{2}}{3} I_{DC}\right)^2 R = \frac{8}{3} I_{DC}^{\ 2} R$$

and losses for the AC bipole are

$$DC\ Losses = 2\ I_{DC}^2 R$$

The ratio of DC losses to AC losses is therefore

$$\frac{DC\ Losses}{AC\ Losses} = \frac{2 \quad I_{DC}^2 \ R}{\frac{8}{3} I_{DC}^2 \ R} = \frac{3}{4}$$

D.2 FORMULA AND DATA FORPRESENT WORTH OF LOSSES

The present worth of losses are given by the following equation:

$$\left(COST_{KW} + \left(PWF * LF * 8760 * COST_{KWH}\right)\right)_{\text{Losses}}$$

where

LF = the loss factor which is the ratio of average losses over the course of a year to losses at peak loading

COST,, = the cost associated with power demand in **$/kW**

COST,,, = the cost of energy in **$/kWh**

PWF = present worth of a uniform series assuming a life expectancy of 30 years and a real rate of return (expected rate of return less inflation) of 8%

LOSSES = losses at peak load in **kW's**

8760 = hours/year

D.3 INPUT ASSUMPTIONS AND RESULTS OF ANALYSIS IN SECTION 6

The following tables represent details of the analysis reported in section 6. Tables D.3.1 and D.3.2 contain results from which the data summarized in Table 6.1 corresponding to the cost-reduced HVDC (50% of today's costs) were derived. The results in Tables D.3.1 and D.3.2 were developed from a spreadsheet analysis described in Section D.4 using data provided in Tables D.3.3 through D.3.6 included below.

Table D.3.1 - Peak Loading Typical for Heavily Loaded Lines Today												
case	ac option		dc option		substation & converter ratings (MW)	ac/dc line thermal capacity (MW)	Break even distance in miles based upon					
	ac circuit	ac voltage (kv)	dc circuit	dc voltage (kv)			peak loading (MW)	cost of losses (miles)	installed cost (miles)	inst.cost & losses (miles)	inst. cost &losses plus series capacitors (miles)
1	ac I-ckt	500	dc bipole	408	1000	2000	1000	192	309	274	267
2	ac I-ckt	345	dc bipole	281	500	1000	500	150	220	200	196
3a	ac 2-ckt	230	dc bipole	281	500	1000	500	43	802	174	163
3b	ac 2-ckt	230	dc bipole	281	1000	1000	500	22	1605	294	275
4	ac I-ckt	345	dc 1 poie	408	500	1000	500	95	182	153	151
5	ac **2-ckt** *	230	3 bipoles	188	500	1000	7 500	48	---	278	255
6a	ac **3-ckt** *	230	3 bipoles	188	- - - -	1500 - - -	1 0	0 0	1 5 516 0	1229 0	0 1936 6
6b	ac **3-ckt** *	230	3 bipoles	188	1500	1500	1000	44	775	309	259
7a	**2-ac** cables	345	dc bipole cable	400	500	1000	500	26	16	17	17
7b	2-ac cables	345	dc bipole cable	400	1000	1000	500	13	31	29	29
* converting existing ac double circuit line - no installation cost included for **2-circuits**												

Table D.3.2 - Peak Line Loading at Thermal Limit

case	ac option: ac circuit	ac option: ac voltage (kv)	dc option: dc circuit	dc option: dc voltage (kv)	dc option: converter ratings (MW)	ac/dc line thermal capacity (MW)	peak loading (MW)	Break even distance in miles based upon: cost of losses (miles)	installed cost (miles)	inst. cost & losses (miles)	inst. cost &losses plus series capacitors (miles)
1	ac 1-ckt	500	dc bipole	408	2000	2000	2000	96	618	291	248
2	ac 1-ckt	345	dc bipole	281	1000	1000	1000	75	439	219	193
3	ac 2-ckt	230	dc bipole	281	1000	1000	1000	22	1605	100	90
4	ac 1-ckt	345	dc 1 pole	408	1000	1000	1000	48	365	154	140
5	ac 2-ckt *	230	3 bipoies	188	1000	1000 / 1500	1000	24		139	124
6	ac 3-ckt *	230	3 bipoles	188	1500	1500	1500	44	775	191	151
7	2-ac cables	345	1 bipole cable	400	1000	1000	1000	21	31	28	28

* con erting existing ac double circuit line - no installation cost included for 2-circuits

Table D.3.3 - Assumed Costs						
loss factor	demand charge ($/kw)	energy charge ($/mw-h)	present worth of losses ($/watt)	cost of series capacitors ($/kvar)	controlled series capacitor cost ($/kvar)	right of way ($/acre)
0.40	900.00	30.00	2.08	15	40	4000

Table D.3.4 - Line and Substation Characteristics														
type	**rated L to L voltage (kv rms)**	**rated peak voltage (kv)**	**resistance each pole or circuit (p.u./mile)**	**reactance each pole or circuit (p.u./mile)**	**line right of way (feet)**	**line surge impedance loading (mw)**	line typical loading (mw)	line thermal rating (mw)	line construction cost (k$/mile)	line right of way cost (k$/mile)	total line installed cost (k$/mile)	substation installed cost/kw ($/kw)	sub-station losses (%)
ac l-ckt	345	282	0.0000468	0.000500	150	415	400	1000	500.00	72.73	572.73	10	0.50
ac l-ckt	500	408	0.0000181	0.000245	200	842	1000	2000	690.00	96.97	786.97	10	0.50
ac 2-ckt	230	188	0.0001590	0.001520	135	274	300	1000	375.00	65.45	440.45	10	0.50
dc bipole	562	281	0.0000446	0.000500	125	415	500	966	330.00	60.61	390.61	50	1.00
dc bipoie	816	408	0.0000172	0.000245	140	842	1000	1934	460.00	67.88	527.88	50	1.00
dc 1 pole	408	408	0.0000172	0.000245	110	842	500	967	300.00	53.33	353.33	50	1.00
3-bipoles	376	188	0.0001510	0.00152	135	274	450	1451	375.00	65.45	440.45	50	1.00
dc cable	800	400	0.0000087	0.0000264	0		1000	1000	2040	0.00	2040.00	50	1.00
2 **ac cables**	345	282	0.0000388		0		1000	1000	4615	0	4615.00	10	0.50
ac 3-ckt	230	188	0.0001590	0.001520	250	411	450	1500	500.00	121.21	621.21	10	0.50

Table D.3.5 - Line and Substation Cost and Losses for Peak Line Loading at Thermal Limits

type	rated L to L voltage (kv rms)	rated peak voltage (kv)	line loading (mw)	line losses at loading (mw/mile)	present worth of line losses at loading (k$/mile)	line losses, ROW & installation present worth for load (k$/mile)	substation losses at loading (mw)	present worth of substation losses (m$)	substation installed cost (m$)	substation installed cost & losses (m$)	cost for series capacitors (k$/mile)
ac l-ckt	500	408	2000	0.7240	1508.39	2295.36	20.00	41.67	40.00	81.67	120.95
dc bipole	816	408	2000	0.5161	1075.31	1603.18	40.00	83.34	200.00	283.34	0.00
ac l-ckt	345	282	1000	0.4680	975.04	1547.77	10.00	20.83	20.00	40.83	62.08
ac 2-ckt	230	188	1000	0.7950	1656.32	2096.77	10.00	20.83	20.00	40.83	105.44
dc bipole	562	281	1000	0.3346	697.07	1087.68	20.00	41.67	100.00	141.67	0.00
dc 1 pole	408	408	1000	0.2581	537.65	890.99	20.00	41.67	100.00	141.67	0.00
3 bipoles	376	188	1000	0.3776	786.68	1227.14	20.00	41.67	100.00	141.67	0.00
dc cable	800	400	1000	0.0653	135.98	2175.98	20.00	41.67	100.00	141.67	0.00
2ac cable	345	282	1000	0.5330	1110.46	5725.46	10.00	20.83	20.00	40.83	0.00
ac 3-ckt	230	188	1500	1.1925	2484.48	3105.69	15.00	31.25	30.00	61.25	237.24
3 bipoles	376	188	1500	0.8496	1770.03	2210.49	30.00	62.50	150.00	212.50	0.00

Table D.3.6 - Line and Substation Cost and Losses for Peak Loading Typical for Heavy Loaded Lines Today

type	rated line to line voltage (kv rms)	rated peak voltage (kv)	line loading (mw)	line losses at loading (mw/mile)	present worth of line losses at loading (k$/mile)	line losses, ROW & installation present 'worth for load (k$/mile)	substation losses at loading (mw)	present worth of substation losses (m$)	substation installed cost (m$)	substation installed cost & losses (m$)	cost for series capacitors (k$/mile)
ac l-ckt	500	408	1000	0.1810	377.10	1164.07	10.00	20.83	20.00	40.83	10.70
dc bipole	818	408	1000	0.1290	268.83	796.71	20.00	41.67	100.00	141.67	0.00
ac 1-ckt	345	282	500	0.1170	243.76	816.49	5.00	10.42	10.00	20.42	5.83
ac 2-ckt	230	188	500	0.1988	414.08	854.53	5.00	10.42	10.00	20.42	19.94
dc bipole	562	281	500	0.0836	174.27	564.87	10.00	20.83	50.00	70.83	0.00
dc 1 pole	408	408	500	0.0645	134.41	487.75	10.00	20.83	50.00	70.83	0.00
3 bipoles	376	188	500	0.0944	196.67	637.12	10.00	20.83	50.00	70.83	0.00
ac 3-ckt	230	188	1000	0.5300	1104.21	1725.42	10.00	20.83	20.00	40.83	94.74
dc cable	800	400	500	0.0163	33.99	2073.99	10.00	20.83	50.00	70.83	0.00
2ac cable	345	282	500	0.2078	432.93	5047.93	5.00	10.42	10.00	20.42	0.00
3 bipoles	376	188	1000	0.3776	786.68	1227.14	20.00	41.67	100.00	141.67	0.00

D.4 SAMPLE CALCULATIONS & SPREAD SHEETS FOR RESULTS IN SECTION D.3

D.4.1 Sample Calculation: Case 1: ± 408 kV Bipole Vs. a 500 kV Single Circuit AC

The AC impedances are expressed in per unit on a **100** MVA three-phase system base. The base impedance, **(BASEZ),** is therefore:

$$(\mathbf{BASEZ})\frac{OHMS}{PU} = \frac{((\mathbf{VLL})kV)^2}{(3\phi\mathbf{BASE})\ MVA} = \frac{((\mathbf{VLG})kV)^2}{(1\phi\mathbf{BASE})\ MVA}$$

where **VLL = he** to line RMS voltage

VLG = line to ground RMS voltage = **VLL /** $\sqrt{3}$

3Φ BASE = System 3Φ Power Base

1Φ BASE = System 1Φ Power Base = **3Φ Base/3**

For a 100 **MVA** system base and 500 **KV**:

$$(\text{BASEZ}) = \frac{500^2}{100} = \underline{2500}$$

In the spreadsheet for direct comparison of AC and DC per unit impedance values, we have used the same impedance base **(BASEZ)** for both AC and DC **when** the peak AC voltage

$\left|\mathbf{VLL}\frac{\sqrt{2}}{\sqrt{3}}\right)$ equals the DC pole voltage magnitude, VDC.

$$(\mathbf{BASEZ})\frac{OHMS}{PU} = \frac{((\mathbf{VLL})kV^2}{(3\phi\mathbf{BASE})MVA} = \frac{3/2((\mathbf{VDC})kV)^2}{(3\phi\mathbf{BASE})MVA}$$

For a **100** MVA system base and 408 KV DC:

$$(\mathbf{BASEZ})\frac{OHMS}{PU} = \frac{3/2(408)^2}{100} = \mathbf{2500}$$

Assume a real rate of return of 8% and a life expectancy of 30 years then, as defined in Section D.2:

(PRESENT WORTH OF A UNIFORM SERIES) $\doteq \underline{11.26} \frac{\$}{\$ / YR}$; **see top of page D.14.**

Also assume:

PWF = PRESENT WORTH OF A UNIFORM SERIES)
(LOSS FACT OR) = 0.4
(DEMAND CHARGE) = 900 *\$/KW*
(ENERGY CHARGE) = 30.0 *\$ / (MW-H)*

$$\text{(COST OF LOSSES)}\ \$/W = \text{(PWF)}\ \$/\$/YR \times \text{(LOSS FACTOR)}$$
$$\times\ 8760\ H/YR\ \text{(ENERGY CHARGE)}\ \$/(MW-H) * 10^{-6}\ MW/W$$
$$+\ \text{(DEMAND CHARGE)}\ \$/KW * 10^{-3}\ KW/W$$
$$= 11.26 * 0.4 * 8760 * 30 * 10^{-6}$$
$$+\ 900 * 10^{-3}$$
$$= 2.08\ \$/W$$

$$\text{(DC LINE LOSSES)}MW/MILE = 2 * \left((I_{DC})KA\right)^2 * (I\&)\ OHMS/MILE$$
$$= 2 * \left(\frac{\text{(LOADING)}MW}{2(V_{DC})KV}\right)^2 * (R_{DC})PU / MILE * \text{(BASEZ)}\frac{OHMS}{PU}$$

where	**(LOADING)**	is the loading of the DC bipole
	(V_{DC})	is the magnitude of the pole voltage
	(I_{DC})	is the current
	(R_{DC})	is the DC line resistance per mile

For a $\pm$ 408 KV DC bipole loading at 1000 MW (see Table D-3.4):

$$\text{(DC LINE LOSSES)} = 2 * (500 / 408)^2 * 0.0000172 * 2500$$
$$= \underline{0.129}\ MW/MILE$$

$$\text{(AC LINE LOSSES)}\frac{MW}{MILE} = 3\left((I_{AC})KA\right)^2 * (R_{AC})\,\frac{OHMS}{MILE}$$

$$= 3\left(\frac{\text{(LOADING)}MW/3}{\text{(VLG)}KV}\right)^2 * (R_{AC})\frac{PU}{MILE}\,\text{(BASEZ)}\,\frac{OHMS}{PU}$$

$$= 3\left(\frac{\text{(LOADING)}MW/3}{\text{(VLL)KV}\ /\ \sqrt{3}}\right)^2 * (R_{AC})\frac{PU}{MILE}\text{(BASEZ)}\,\frac{OHMS}{PU}$$

where **(LOADING)** is the loading of a single circuit three phase line which is assumed to be at unity power factor. To calculate the crossover distance this loading is set equal to the loading of the DC bipole.

(VLG) is the line to ground RMS voltage

(VLL) is the line to line RMS voltage

(R_{AC}) is the AC line resistance per mile

For a single circuit 500 KV AC line loaded at 1000 (see Table D.3.4):

$$\text{AC LINES LOSSES}=\left(\frac{1000}{500}\right)^2 * 0.0000181 * 2500 = \underline{0.181}MW\ /\ MILE$$

$$\text{(AC COST)}\$ = 2\text{(SUBSTATION COST)}\ \$/KW\ *\text{(RATING)}MW*1000\ KW/MW$$

$$+\ 2\ \text{(PU SUBSTATION LOSSES)(RATING)}MW*\text{(COST OF LOSSES)}\ \$/W\ 10^{-6}\ W/MW$$

$$+\ \text{(AC LINE COST)}K\$\ /\ MILE*1000\ \$/K\$\ \text{(DISTANCE)}MILES$$

$$+\ \text{(AC LINE COST)}\ MW/MILE$$

$$+\ \text{(COST OF LOSSES)}\ \$/W*10^{-6}\ W/MW\ *\ \text{(DISTANCE)}MILES$$

For 500 KV AC at 1000 *MW*

$$\begin{aligned}
\text{(AC COST)} &= 2*10*1000*1000 \\
&\quad +2*0.005*1000*2.08*10^6 \\
&\quad +787*1000*\text{DISTANCE} \\
&\quad +0.1810*2.08*10^6*\text{DISTANCE} \\
&= 20*10^6+20.8*10^6 + (.787+.3765)*10^6*\text{DISTANCE} \\
&= 40.8*10^6+1.164*10^6*\text{DISTANCE}
\end{aligned}$$

(DC COST) *\$* = 2 (SUBSTATION COST) *\$/KW* ***(RATING)** *MW* "1000 *KW/MW*

+ 2(P.U. SUBSTATION **LOSSES)(RATING)** *MW* *(COST OF **LOSSES)** *\$/W* **10^6** *W/MW*

+ (DC LINE COST) *K\$/MILE* ***1000** *\$/K\$* ***(DISTANCE)** *MILES*

+ (DC LINE LOSSES) *MW/MILE*

+(COST OF LOSSES) *\$/W* * 10^6* *W/MW* * (DISTANCE) *MILES*

For $\pm$ 408 **KV** at 1000 (see Table D.3.4):

$$
\begin{aligned}
\text{(DC COSTS)} &= 2*50*1000*1000 \\
&\quad + 2*0.01*1000*2.08*10^6 \\
&\quad + 528*1000*\text{DISTANCE} \\
&\quad + 0.1290*2.08*10^6 *\text{DISTANCE} \\
&= 100*10^6+41.6*10^6+(.528+.2683)*10^6*\text{DISTANCE} \\
&= 141.6*10^6+0.796*10^6 *\text{DISTANCE}
\end{aligned}
$$

Equating the AC **and** DC cost at 1000 *MW:*

$$141.6*10^6+0.702*10^6 *\text{DISTANCE} =40.8*10^6 +1.023*10^6 *\text{DISTANCE}$$

Solving for **DISTANCE:**

$$\text{DISTANCE} = \frac{1416 - 40.8}{1.168 - 796} = \frac{100.8}{0.368} = \underline{274}\ \textit{MILES}$$

This value is **found in** Table **D.3.1,** Case 1, next to last column on the **right**. The last column (containing 267 miles) includes the cost of just enough series capacitor compensation to achieve **unity** power factor of the assumed loading. For Case 1, the added cost is \$10.70 per mile as derived in Section **D.5**.

D.4.2 Excel Spreadsheets Corresponding to Results in Section D.3

The following six pages contain the subject spreadsheets.

real rate of return (percent)	life (years)	present worth of a uniform series
8	30	11.26

loss factor	demand charge ($/kw)	yearly demand charge ($/kw/yr)	energy charge ($/mw-h)	present worth of losses ($/watt)	cost of series capacitors ($/kvar)	controlled series capacitor cost ($/kvar)	right of way ($/acre)
0.40	900.00	79.94	30.00	2.08	15	40	4000

type	rated line to lin voltage (kv rms)	rated peak voltage (kv)	resistance each pole or circuit (p.u./mile)	reactance each pole or circuit (p.u./mile)	line right of way (feet)	line surge impedance loading (mw)	line typical loading (mw)	line thermal rating (mw)	line construction cost (k$/mile)	line right of way cost (k$/mile)	total line installed cost (k$/mile)	substation installed cost/kw ($/kw)	sub-station losses (%)
ac 1-ckt	345	282	0.0000468	0.000500	150	415	400	IWO	500.00	72.73	572.73	10	0.50
ac 1-ckt	500	408	0.0000181	0.000245	200	842	1000	2000	690.00	96.97	786.97	10	0.50
ac 2-ckt	230	188	0.0001590	0.001520	135	274	300	1000	375.00	65.45	440.45	10	0.50
lc bipole	562	281	0.0000446	0.000500	125	415	500	966	330.00	60.61	390.61	50	1.00
lc bipole	816	408	0.0000172	0.000245	140	842	1000	1934	460.00	67.88	527.88	50	1.00
c 1 pole	408	408	0.0000172	0.000245	110	842	500	967	300.00	53.33	353.33	50	1.00
-bipoles	376	188	0.0001510	0.00152	135	274	450	1451	375.00	65.45	440.45	50	1.00
lc cable	800	400	0.0000087	0.0000264	0		1000	1000	2040	0.00	2040.00	50	1.00
ac cabl	345	282	0.0000388		0		1000	1000	4615	0	4615.00	10	0.50
ac 3-ckt	230	188	0.0001590	0.001520	250	411	450	1500	500.00	121.21	621.21	10	0.50

type	rated line to line voltage (kv rms)	rated peak voltage (kv)	line loading (mw)	line losses at loading (mw/mile)	present worth of line losses at loading (k$/mile)	line losses, row & installation present worth for load (k$/mile)	substation losses at loading (mw)	present worth of substation losses (m$)	substation installed cost (m$)	substation installed cost & losses (m$)	cost for series capacitors (k$/mile)
ac 1-ckt	500	408	1000	0.1810	377.10	1164.07	10.00	20.83	20.00	40.83	10.70
dc bipole	816	408	1000	0.1290	268.83	796.71	20.00	41.67	100.00	141.67	0.00
ac 1-ckt	345	282	500	0.1170	243.76	816.49	5.00	10.42	10.00	20.42	5.83
ac 2-ckt	230	188	500	0.1988	414.08	854.53	5.00	10.42	10.00	20.42	19.94
dc bipole	562	281	500	0.0836	174.27	564.87	10.00	20.83	50.00	70.83	0.00
dc 1 pole	408	408	500	0.0645	134.41	487.75	10.00	20.83	50.00	70.83	0.00
3 bipoles	376	188	500	0.0944	196.67	637.12	10.00	20.83	50.00	70.83	0.00
ac 3-ckt	230	188	1000	0.5300	1104.21	1725.42	10.00	20.83	20.00	40.83	94.74
dc cable	800	400	500	0.0163	33.99	2073.99	10.00	20.83	50.00	70.83	0.00
2ac cable	345	282	500	0.2078	432.93	5047.93	5.00	10.42	10.00	20.42	0.00
3 bipoles	376	188	1000	0.3776	786.68	1227.14	20.00	41.67	100.00	141.67	0.00

type	rated line to line voltage (kv rms)	rated peak voltage (kv)	line loading (mw)	line losses at loading (mw/mile)	present worth of line losses at loading (k$/mile)	line losses, row & installation present worth for load (k$/mile)	substation losses at loading (mw)	present worth of substation losses (m$)	substation installed cost (m$)	substation installed cost & losses (m$)	cost for series capacitors (k$/mile)
ac 1-ckt	500	408	2000	0.7240	1508.39	2295.36	20.00	41.67	40.00	81.67	120.95
dc bipole	816	408	2000	0.5161	1075.31	1603.18	40.00	83.34	200.00	283.34	0.00
ac 1-ckt	345	282	1000	0.4680	975.04	1547.77	10.00	20.83	20.00	40.83	62.08
ac 2-ckt	230	188	1000	0.7950	1656.32	2096.77	10.00	20.83	20.00	40.83	105.44
dc bipole	562	281	1000	0.3346	697.07	1087.68	20.00	41.67	100.00	141.67	0.00
dc 1 pole	408	408	1000	0.2581	537.65	890.99	20.00	41.67	100.00	141.67	0.00
3 bipoles	376	188	1000	0.3776	786.68	1227.14	20.00	41.67	100.00	141.67	0.00
dc cable	800	400	1000	0.0653	135.98	2175.98	20.00	41.67	100.00	141.67	0.00
2ac cable	345	282	1000	0.5330	1110.46	5725.46	10.00	20.83	20.00	40.83	0.00
ac 3-ckt	230	188	1500	1.1925	2484.48	3105.69	15.00	31.25	30.00	61.25	237.24
3 bipoles	376	188	1500	0.8496	1770.03	2210.49	30.00	62.50	150.00	212.50	0.00

Peak Loading Typical for Heavily Loaded Lines Today

case	ac option: ac circuit	ac option: ac voltage (kv)	dc option: dc circuit	dc option: dc voltage (kv)	substation & converter ratings (MW)	ac/dc line thermal capacity (MW)	peak loading (MW)	Break-even distance in miles based upon: losses (miles)	installed cost (miles)	cost & losses (miles)	cost &losses plus series capacitor (miles)	comments
1	ac 1-ckt	500	dc bipole	408.00	1000	2000	1000	192.42	308.77	274.48	266.72	
2	ac 1-ckt	345	dc bipole	281.00	500	1000	500	149.90	219.63	200.38	195.84	
3a	ac 2-ckt	230	dc bipole	281.00	500	1000	500	43.44	802.43	174.06	162.85	
3b	ac 2-ckt	230	dc bipole	281.00	1000	1000	500	21.72	1604.86	294.17	275.22	full capacity with 1 out
4	ac 1-ckt	345	dc 1 pole	408.00	500	1000	500	95.27	182.32	153.36	150.69	
5	ac 2-ckt *	230	3 bipoles	188.00	500	1000 / 1500	500	47.91		277.90	254.55	convert ac to dc
6a	ac 3-ckt *	230	3 bipoles	188.00	1000	1500	1000	65.61	516.35	229.12	192.52	
6b	ac 3-ckt *	230	3 bipoles	188.00	1500	1500	1000	43.74	774.52	308.84	259.50	full capacity with 1 out
7a	2-ac cable	345	dc cable	400.00	500	1000	500	26.11	15.53	16.95	16.95	cable underutilized
7b	2-ac cable	345	dc cable	400.00	1000	1000	500	13.06	31.07	28.65	28.65	full capacity with 1 out

● converting existing ac double circuit line - no installation cost included for 2-circuits

Peak Line Loading at Thermal Limit

case	ac option: ac circuit	ac option: ac voltage (kv)	dc option: dc circuit	dc option: dc voltage (kv)	converter ratings (MW)	ac/dc line thermal capacity (MW)	peak loading (MW)	Break-even distance in miles based upon: losses (miles)	installed cost (miles)	cost & losses (miles)	cost &losses plus series capacitor (miles)	comments
1	ac 1-ckt	500	dc bipole	408.00	2000	2000	2000	96.21	617.54	291.35	248.02	
2	ac 1-ckt	345	dc bipole	281.00	1000	1000	1000	74.95	439.27	219.16	193.11	
3	ac 2-ckt	230	dc bipole	281.00	1000	1000	1000	21.72	1604.86	99.93	90.47	
4	ac 1-ckt	345	dc 1 pole	408.00	1000	1000	1000	47.63	364.64	153.53	140.27	
5	ac 2-ckt *	230	3 bipoles	188.00	1000	1000 / 1500	1000	23.96		138.95	123.92	convert ac to dc
6	ac 3-ckt *	230	3 bipoles	188.00	1500	1500	1500	43.74	774.52	191.30	151.22	
7	2-ac cable	345	dc cable	400.00	1000	1000	1000	21.38	31.07	28.41	28.41	

* converting existing ac double circuit line - no installation cost included for 2-circuits

D.5 CALCULATION OF COST OF REQUIRED SERIES COMPENSATION

D.5.1 Derivation of Equation for MVAR of Compensation

This section derives the equation for the var compensation needed with AC transmission to fully compensate for the var losses at the desired loading.

For the calculation, we take advantage of the fact that at surge impedance loading and rated voltage the vars supplied by the line charging equals the vars consumed by the line inductance. This is shown below. By definition:

$$SIL = V^2 \sqrt{\frac{B}{X}}$$

Where
- **SIL** is the surge impedance loading (MVA)
- **V** is rated line-to-ground voltage (kV)
- **B** is the line charging admittance per unit length (MHOS)
- X is the live reactance per unit length (OHMS)

The conductor current at surge impedance loading is, therefore,

$$I = \frac{(SIL)}{V} = V \sqrt{\frac{B}{X}} \text{ KA}$$

The vars supplied per unit length by the conductor charging is

$$Q_C = V^2 B \text{ MVAR}$$

The vars absorbed by the conductor reactance per unit length is

$$Q_L = I^2 X = \left(V \sqrt{\frac{B}{X}}\right)^2 X = V^2 B \text{ MVAR}$$

Since Q_C equals Q_L, the total var consumption of the line is zero at surge impedance loading.

It is assumed that the reactive compensation required for other levels of loading will be located so the voltage profile on the line remains flat, i.e., the voltage magnitude is the same at all line locations. It is further assumed that the line will be operated at rated voltage.

The vars supplied q_c per unit length by the line charging will, therefore, still be equal to V^2B MVAR. This, as shown above, is also equal to the reactive power absorbed by the line inductance at surge impedance loading (I^2X). The vars absorbed per unit length by the line inductance at surge impedance loading (I^2X). The vars absorbed per unit length by the line reactance q_L at some other loading, LOAD, are given by:

$$q_L = I^2 X = \left(\frac{LOAD}{V}\right)^2 X \text{ MVAR}$$

where I is the current at the new loading (KA)
LOAD is the new conductor loading (MVA)

The required compensation for one-phase equals the difference between the vars supplied by the charging and the vars absorbed by the reactance.

$$q = q_L - q_c = \left(\frac{LOAD}{V}\right)^2 X - \left(\frac{SIL}{V}\right)^2 X \text{ MVAR}$$

For a three-phase line, the total compensation per unit length will be three times this amount.

$$q_3 = 3\left\{\left(\frac{LOAD_3/3}{VLL/\sqrt{3}}\right)^2 X - \left(\frac{SIL_3/3}{VLL/\sqrt{3}}\right)^2 X\right\} = \left(\frac{LOAD_3}{VLL}\right)^2 X - \left(\frac{SIL_3}{VLL}\right)^2 X \text{ MVAR}$$

where q^3 is total three-phase compensation (MVAR)
LOAD, is three-phase loading (MVA)
VLL is line-to-line voltage (kV)
SIL_3 is three-phase surge impedance loading (MVA)

D.5.2 Sample Calculations of Cost of Compensation

First for Case lin Table D.3.1: Apply the above analysis to a 500 kV line with the following characteristics (see Table D.3.4)

$$SIL_3 = 842 \text{ MVA}$$
$$X = .000246 \text{ p.u./mile}$$
$$= .000245 * \frac{500^2}{100} \text{ OHMS / mile}$$
$$= .6125 \text{ OHMS / mile}$$

If it is loaded to 1000 MW

$$q_3 = \left(\frac{1000}{500}\right)^2 0.6125 - \left(\frac{842}{500}\right)^2 0.6125$$

$$= .713 \text{ MVAR/mile}$$

Ifvar compensation cost 1 5$/KVAR, the cost will be

$$\text{COST}=.713 \frac{\text{MVAR}}{\text{MILE}} * 15\$/\text{KVAR} * 1000 \frac{\text{KVAR}}{\text{MVAR}}$$
$$=\$10.7 * 1000/\text{mile}$$

This checks with the spreadsheet results: specifically: Table D.3.6, page D-15, first row in top table.

Now Consider 230 *kV* cases. Apply the above analysis to a double circuit 230 kV line with the following characteristics (see Table D.3.4)

$$\text{SIL}, = 274 \text{ MVA (total for both circuits)}$$
$$X = 0.00152 \text{ p.u./mile}$$
$$= 0.00152 * \frac{230^2}{100} \text{ OHMS/mile}$$
$$= 0.804 \text{ OHMS/mile}$$

If it is loaded to 500 MW, the compensation required for each circuit is

$$q_3 = \left(\frac{500/2}{230}\right)^2 0.804 - \left(\frac{274/2}{230}\right)^2 0.804$$

$$= (1.18)\ 0.804 - (0.355)\ 0.804$$

$$= 0.663 \text{ MVAR/mile}$$

For both circuits, it will be twice this, or 1.327 MVAR/MILE

Ifvar compensates, cost 15$/KVAR, the cost will be

$$\text{COST} = 1{,}327 * 15 * 1000$$

$$= \$19.9 * 1000/\text{mile}$$

This checks with the spreadsheet results; namely Table D.3.6, page D-15, fourth row in top table.

APPENDIX E

CONSIDERATIONS CONCERNING THE MANUFACTURE, TRANSPORT AND INSTALLATION OF HVAC AND HVDC SUBMARINE CABLES

E.1 INTRODUCTION

This appendix is a continuation of the discussion in Section 7. Though the types of cable, the transportation and laying vessels, and the laying and embedding equipment cannot be regarded as commodity items the respective technologies are all available and proven so that no new developments are necessary in order to manufacture the HVDC or HVac cables proposed in the study documented in Section 7.2 of this report, transport them in single lengths of up to 130 km from plants (in Europe or Japan) and lay and embed them in a major river in the northeastern part of the United States. The following is a brief summary of the technologies that would be involved in such a project.

E.2 THE MANUFACTURING PROCESS

The manufacture of HVDC MI submarine cable is a high-technology operation, requiring custom designed equipment for carrying out a number of complex manufacturing processes and capable of handing the large volumes and weights involved in the production of extremely long manufacturing and shipping lengths. The manufacturing cycle consists of a number of seperate operations which are carried out sequentially to produce the finished cable. A description of each of the major processes is now given:

Conductor Stranding

In the case of the modern conci or segmental conductor, preshaped keystone conductor segments are applied in a number of layers around a solid central rod of circular section and typically of about 10 mm in diameter. The stranding machine generally consists of a series of rotating cages with spools or bobbins in multiples of six containing the shaped conductor segments. The make-up of a typical three layer conductor would be as follows:

- the central round conductor
- a first layer with 6 segments
- a second layer with 6 segments larger than those used in the first layer
- a third layer with 12 segments similar in size to those used in the second layer

Since the bobbin capacity is limited these are replaced several times during the manufacture of a 40 - 50 km length of conductor. Prior to exiting the strander a paper lapping head wraps a temporary paper tape protection around the conductor.

Paper Lapping

The finished conductor is fed into the paper lapping enclosure - a controlled humidity environment necessary to maintain the insulating paper at a low moisture content to facilitate the paper drying process. The paper taping or lapping process is achieved by passing the conductor through a series of lapping heads. Each lapping head generally contains 12 paper pads, 600 mm or so in diameter, and since the thickness of each tape is usually in the range of 100 - 200 microns, the conductor needs to pass through a series of lapping heads to produce insulation thicknesses of around 20 mm. The lapping tension under which each tape is applied is controlled to produce the correct degree of insulation compactness which is always a compromise between achieving good electrical properties and adequate tensile bending performance. Good electrical properties rely, especially in the case of HVDC MI insulation, on the compactness of the insulation but if it is too compact the paper tapes cannot slide over each other during bending of the cable and the result is creasing and tearing of the tapes.

The Impregnation Process

The next phase in the manufacturing process is the final drying of the paper insulation and impregnation with the viscous dielectric compound. This process, which is probably the most critical operation is carried out in a huge manufacturing tank capable of withstanding both vacuum and internal pressurization. Paper drying is carried out by applying heat, usually by passing dc current through through the conductor as well as heating the tank walls, to drive off the moisture from the paper and vacuum to remove the moisture from the tank. When drying has reached completion, hot degasified impregnant - a viscous compound in the case of MI cables or a low viscosity synthetic fluid in the case of SCF'F cables - is introduced and the tank pressurized under dry nitrogen gas to assist impregnation.

Lead and Polyethylene Sheathing Processes

Following impregnation the cable core is fed directly from the impregnating tank into the lead press. Lead sheathing is a relatively old and well established technological process but is nevertheless critical to the extent that it has to be continuous which means running the lead press for several weeks without interruption. The leaded cable is then polyethylene sheathed in a seperate operation. A spark test in series with the extrusion line is used to check the quality of the extrusion.

Armoring

Galvanized steel armor wires of 6 to 8 mm in diameter (or strips with a rectangular cross section) are applied in rotating cage - often a single carriage - armoring machine with 50 plus spools or bobbins. As was the case for conductor stranding the capacity of the bobbins is limited so that the bobbins are replaced from time to time and the wires joined by welding.

E.3 DESCRIPTION OF A MANUFACTURING PLANT

A detailed description of the equipment used in such a plant has been published by Pirelli Cables (UK) Ltd. for their plant which was built in the early 1980s to manufacture the U.K.'s 200 km share of the 266 kV dc Cross Channel cable.

An important feature of a modern plant is the use of turntables. The practice of coiling the cable, which introduces a 360 deg. axial twist, has now largely been abandoned because of the sensitivity of the thin insulating-paper tapes to axial torsion. Turntables are therefore used to avoid such torsion. For the same reason the impregnating tank itself is rotatable. In the Pirelli plant the tank is mounted on 90 bogey wheels with integral coil suspension units and rotates on twin circular rails embedded in the factory floor.

As far as the writer is aware HVDC cables for 3 50 kV and above have never been coiled.

E.4 MANUFACTURING CAPABILITY OF A MODERN SUBMARINE CABLE PLANT

A modem plant with a single manufacturing line can produce around 130 kms of 500 MW (or 500 MVA) submarine cable per year. This represents three 4-month manufacturing cycles.

ITEM	UNITS	QUANTITY
Factory Layout	m	120 x 80
Stranding:		
- No. of carriages	-	3
- Speed	m/min	15
- Max. Conductor Cross Section	mm2	2,000
- bobbin capacity	km	2
Impregnation Tank:		
- Diameter	m	16.75
- Capacity	m3	272
- Weight(empty)	tons	675
- Weight(fully loaded)	tons	>1,300
- Lid weight	tons	110
- Process Time *	weeks	5 - 6
Lead/Polyethylene Extrusion		
- Lead Extrusion Speed	m/min	1.7
- Polyethylene Extrusion Speed	m/min	3.9

TABLE E.1: Data on Pirelli Cables (UK) Ltd's Southampton Submarine Cable Plant
* Refers to the 266 kV Cross Channel Cable

E.5 TRANSPORT AND INSTALLATION OF HV SUBMARINE CABLES

E.5.1 Requirements for a Modem Cable Laying Vessel

The choice of cable laying vessel should take into account a number of factors such as the cable type, size and weight, whether the cable has a single- or double-wire armor, the maximum sea water depth, and the subsea environment - sea bottom conditions and bottom currents etc. The following characteristics are considered mandatory:

Rotating Turntable

The importance of minimizing torsional strain in HV submarine cables during manufacture, storage, transport and during the cable laying operation has already been mentioned. The use of a rotating turntable on board the cable laying vessel avoids the need for coiling which as previously explained introduces a 360 deg. axial twist in the cable for each turn. A turntable also permits the use of much smaller bending diameters which means that a given vessel is able to carry more cable on a turntable than it can in a larger diameter coil. This has important cost/scheduling consequences for a major project.

Cable Laying Machinery

The submarine cable must be transferred from the cable laying vessel to the sea bottom (or river bed as in the present study) in a precise and controlled manner. Static tension due mainly to the cable's weight in water, dynamic tensions due to subsea currents, and the vessel's surface speed and wave motion, must all be taken into account and the tension at the laying sheave together with the angle at which the cable enters the water must be controlled accordingly. The angle is controlled by the ships speed while the tension is controlled either by a linear pulling engine or by a cable capstan. In the linear machine the braking force is transmitted through the cable insulation as a shear stress. This situation is less desirable than the mainly normal pressure exerted by the capstan. However, where the maximum water depth is only 100 meters, either would be satisfactory. When a capstan is used a "fleeting" knife or ring must be provided to control the lateral displacement of the cable, necessary to form the successive turns - there are normally three - around the capstan.

Cable Laying Sheave or Wheel

The diameter of the laying sheave or wheel must be at least equal to that of the capstan and both must comply with the minimum safe bending diameter for the cable to be laid. Strictly, only one sheave is necessary for laying but a second one should is considered to be necessary in the event that a repair has to be carried out. In this case the two cable ends would be brought on board necessitating two sheaves.

At least two cable laying vessels are available with the above detailed capabilites namely, the "Skagerrak" (Alcatel Norge) and the "Giulio Verne" (Pirelli Italy).

E.5.2 Description of the Cable Laying Operation

A typical submarine cable laying operation involves the following tasks:

- Mobilisation of the Cable Laying Vessel
- Cable Loading --
- Transport From Cable Plant to Site
- Pulling the Cable End Ashore
- Cable Laying
- Pulling the Second Cable End Ashore
- Unloading of the Surplus Cable
- Demobilization

Of course, in the case of a long cable route which involves multiple shipping lengths, the first cable length would be laid and later recovered e.g. by using a grappling anchor. A "sea splice" would then be made between lengths 1 and 2 and the laying operation continued. This process would be repeated *as* many times as necessary to complete the cable link.

E.5.3 Embedding Capabilities

A full range of burial/trenching equipment is available thanks to the developments carried out for the offshore oil industry. Such equipment falls into one of the following five categories viz.,

- ploughing equipment
- cutter/suction equipment
- water jetting equipment
- dredging equipment
- drilling and blasting equipment

For a river bed installation ploughing or water jetting would appear to be the obvious solution. Ploughing has the advantage that the laying and embedding are carried out in one operation thus minimizing the risk to the cable from river traffic while it remains on the river bed surface.

Embedding by water jetting usually requires two separate operations. The cable would be first placed on the river bed then a remotely controlled jetting machine, which has been used down to depths of greater than 500 meters, follows the prelaid cable, cuts the trench and simultaneously fluidises the river-bed material so that the cable sinks into the trench under it's own weight. When the machine has passed a given location the fluidised material settles over the cable. Backfilling of the trench is thus automatic and a level of 90% level can be achieved. The overall dimensions of such a machine are 5x4x3 meters and its weight in air around 3500 kg while it is neutrally buoyant in water. Typical trench dimension are 1 .O to 1.5 m in depth and 2.0 meters in width and speeds up to several hundred meters per hour can be achieved.

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