IEEE Transactions on Power Delivery, Vol. 5, No. 4, November 1990

APPLICATION ASPECTS OF MULTITERMINAL DC POWER TRANSMISSION

Report of a panel discussion at the 1988 PES Winter Meeting, New York
sponsored by the Working Group on Multiterminal
DC Systems of the IEEE/PES DC Transmission Subcommittee

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Abstract - Multiterminal dc systems have been studied and discussed for many years. However, only recently have such systems been actually implemented. Four systems are presented in this paper: 1) Nelson River, a double-bipole four-terminal system; 2) Pacific HVdc Intertie, a bipolar four-terminal expanded system; 3) SACOI - the Sardinia-Corsica-Italy three-terminal tapped monopolar system; and 4) Hydro-Quebec/New England, a five-terminal bipolar expanded system. Application aspects of each system are presented, with emphasis on the attention required to make each system practical.
Keywords: HVdc, multiterminal, communications, planning, commissioning.

INTRODUCTION TO MULTITERMINAL DC SYSTEMS

This panel session marks a turning point in the 30 year history of dc transmission. It is the departure from restricting applications to links between two dc terminals.

The prospect of dc power interchange between 3 or more terminals (ac/dc converter stations) has been in active consideration for over 25 years [1][2]. A considerable number of publications [3][4] is evidence of an advanced state of possible "multiterminal " design strategies. An IEEE panel session [6] 10 years ago reviewed developments and concluded that there were then no serious barriers to multiterminal applications. Only recently have the applications emerged to match the potential capability.

In common with 2-terminal practice, multiterminal dc system design is application dependent but hitherto design has been hypothetical and preferred approaches have been entirely speculative and inconclusive. At last, there is an opportunity to evaluate design options and performance expectations for actual practical schemes. What may be critical for one application may be of relatively minor concern for another. The system designs would be expected to reflect the priorities.

89 SM 612-3 PWRD A paper recommended and approved by the IEEE Transmission and Distribution Committee of the IEEE Power Engineering Society for presentation at the IEEE/PES 1989 Summer Meeting, Long Beach, California, July 9 - 14, 1989. Manuscript submitted January 31, 1989; made available for printing April 21, 1989.

This introductory presentation will not comprehensively review previous developments, nor will it provide a detailed theoretical background. As a brief introduction to the contributions of the other panel members, it emphasizes those features which distinguish multiterminal from existing 2-terminal systems, together with some of the design options available for planning.

Differences Between 2-Terminal and Multiterminal DC Systems

Terminals A and B in Fig. 1 are connected in a typical 2-terminal bipole with a common current and voltage on each pole. The dc connection shown by bold lines is one connection option for a minimal (3-terminal) multiterminal scheme using a parallel connection at a common pole voltage. Connection of a rectifier or an inverter must match the selected common pole polarity. Therefore, a change in designated operation between rectification and inversion for a terminal power reversal requires converter polarity switching at its dc terminals as well as a change in control mode.

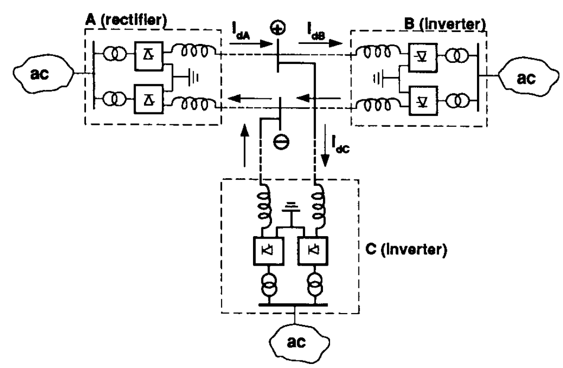

Fig. 1. Extension of a two-terminal system to a third terminal.

There is some enthusiasm for potential series connections for small power taps. The projects to be discussed in this panel session are all parallel connections to which this introduction will be confined.

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Some of the differences that multiterminal operation introduce are itemized below:

- Each terminal has the potential to operate at a different current and power. The steady-state control characteristics may have certain refinements but will be basically the same as 2-terminal methods: the ability to operate at extremes of dc voltage limited by minimum firing angle (rectifier) and minimum extinction angle (inverter), linked by a constant current mode. In operating at a common dc voltage, every terminal except one will control its own current with the remaining terminal setting the voltage at a current imposed by the other terminals, providing that there is no overriding current limit. An incompatible set of current orders or limits could either produce an overload at the voltage controlling terminal or a run-down of the entire system. For example, in Fig. 2, rectifier A and inverter C operate at their set currents while B accepts the excess current from A. Terminal B sets the system voltage as an inverter with minimum extinction angle but, here, takes an overload current. To avoid this, the current settings are coordinated via some form of system current balancer.

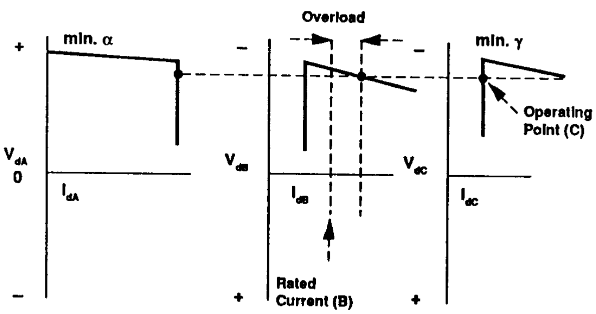

Fig. 2. Overload caused by uncoordinated current settings.

- Transient disturbances at one terminal (e.g., commutation failures) which temporarily reduce the dc voltage affect the power distribution at all terminals. An acceptable response is an issue important to the integrity of the system.
- Current can be transiently diverted to a faulted inverter. The greater the disparity between inverter ratings, the greater the potential per-unit transient overcurrent at the lowest rated inverter. This has implications of thyristor valve design, selection of smoothing reactor and recovery response characteristics.
- Each section of dc line will generally carry different currents. The line ratings should accommodate immediate requirements, and also take into account any projected multiterminal expansion.
- Following a sustained pole-to-ground dc fault at a location shown in Fig. 3, A and B can resume service at modified power levels provided the correct isolating switch is opened within the deenergized period. For switches A and B to remain closed, the protection must discriminate between line sections. With one pole of terminal C now isolated, ground current due to pole current imbalance can be avoided at the expense of (i) blocking the other pole of C, or (ii) provision of a metallic neutral conductor.

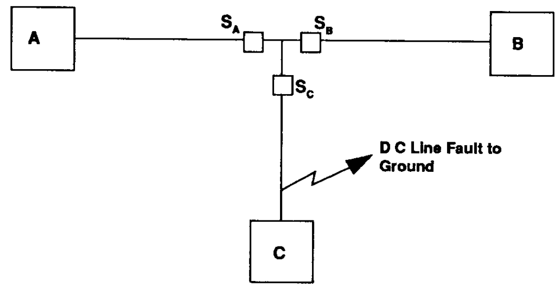

Fig. 3. Isolation of dc line fault.

- There is an implication for dc filter design and interference evaluation because the sources of dc harmonics become compounded [5].
- Load flow and stability programs have to be able to account for an internal dc load flow, various control system strategies and power scheduling between the terminals.
- The prospect of a low power tap operating at a low current but at full dc voltage places constraints on the thyristor selection for optimum valve design.
- When the multiterminal system overlays interconnected or isolated ac systems, there is full controllability (steady-state and dynamic) over the power interchange between the ac connection points, irrespective of any transmission economic advantages.

Selection From Design Possibilities

In consideration of the above factors to be taken into account in arriving at a design, a number of options are available to meet the needs of a particular application. They include:

- Since dc circuit breakers are now available, it has to be judged whether the modest improvement in switching time for power restoration (e.g., for transient stability) is worth the increased cost and uncertain reliability compared to simpler switching alternatives.
- Inverters can be operated at a higher than minimum extinction angle. The value of this extra margin of immunity to ac voltage dips (by reducing the incidence of commutation failures) must be weighed against increased converter ratings, and also increased reactive power consumption. A related option is to operate all inverters at increased extinction angles on current control.
- Once the control strategy has been selected, the communication system can be specified to meet the security demanded by the application. There is an option of incorporating special control characteristics to improve the response to disturbances and to permit decentralized operation sufficient to withstand a communication failure [7][8].
- There is a possibility to design for future expansion by anticipating increased line and converter ratings, and providing switchyard provision for any additional dc interconnection.
- In contemplating expansion, there is the additional question whether equipment including control circuits will possibly be supplied by a different manufacturer and whether any measures should be taken initially to minimize future compatibility problems.
- A strategy is required for accommodating imbalanced currents due to a pole outage at one terminal, including the considerations of metallic

neutral conductor(s) and restrictions in ground currents.

- Other issues which have a bearing on the selection of options are the strength of the ac system at any terminal, any unusual expected temporary overvoltages, and any onerous resonances. The selection of smoothing reactors takes on additional significance with the prospect of controlling the rate of increase of temporarily diverted dc current to a faulted inverter.

Concluding Comments

The above considerations have been adapted to the specific requirements of the projects to be described by the other panel members. It can be expected that there are demands that could not have been anticipated in the past in hypothetical studies. Consequently, practical schemes will give rise to novel solutions and developments.

PARALLEL OPERATION OF THE NELSON RIVER HVDC SYSTEM

Introduction

In 1966 HVdc technology was selected and approved as the transmission means for linking the generating facilities on the Nelson River with the load center of the Manitoba Hydro electrical system in Winnipeg. This selection was based upon the projected economics and the stability of the interconnected network. Commercial operation of the Nelson River HVDC system followed in 1972 with the successful commissioning of the first three valve groups of Bipole 1.

One important constraint placed upon the transmission system was the reliability criterion which required that the loss of a transmission tower should not affect the ability to transmit full power. Hence the initial concept for Bipole 1 incorporated two transmission lines to allow for the tower failure contingency. The transmission line design of each circuit was based upon a 3600 A rating, foreseeing the future advantage of emergency parallel operation when Bipole 2 was completed, rather than constructing a third line at that time.

This high level of reliability is essential because at the present time the two Nelson River generating plants comprise approximately 57 percent of the electrical capacity in the province of Manitoba. With the completion of the third plant at Limestone in 1992 this proportion will rise to 68 percent. Figure 4 is an illustration of the single line diagram of the dc transmission link showing the connection of the northern generation to the southern Manitoba system. These two systems are completely asynchronous. The dc lines form the only link.

The specification for the dc converter equipment for Bipole 2 was issued in 1974 and it included a request for the manufacturer to supply control equipment to permit parallel operation with Bipole 1 under emergency conditions. In addition to being a pioneering effort in the commercial operation of multiterminal systems the control concept had to deal with the different equipment of the two bipoles. The normal operating voltages are different (Bipole 1 operates at 450 kV with 3 X 150 kV 6 pulse valve groups per pole; Bipole 2 operates at 500 kV with 2 X 250 kV 12 pulse valve groups per pole). The valve technologies are different (Bipole 1 employs mercury arc valves and Bipole 2 utilizes thyristors) and the equipment suppliers are different.

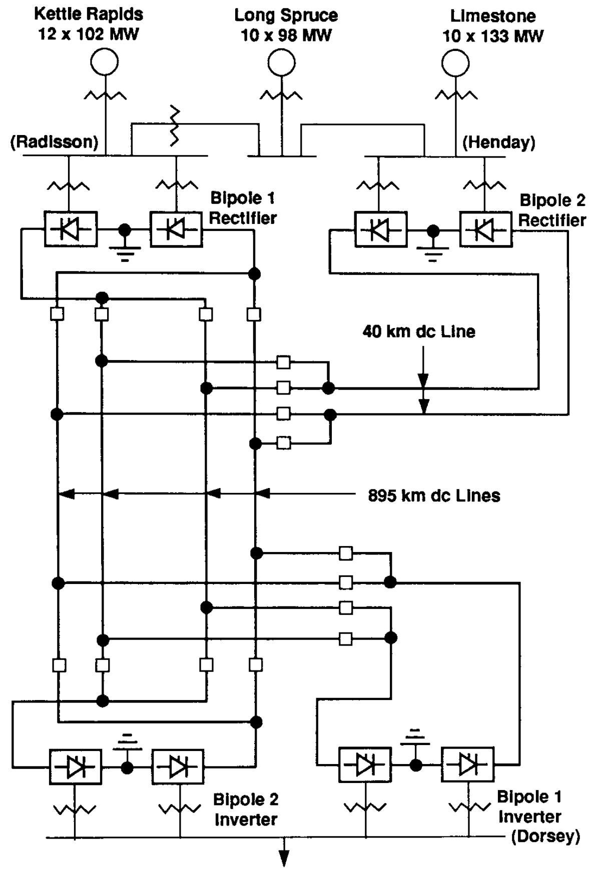

Fig. 4. Nelson River system one-line diagram.

Paralleling Sequence

The parallel connection of the two bipoles [9][10] can be initiated either automatically from the dc line protection or manually by the operator, depending upon the selector switch position. The command to commence parallel operation initiates a controlled sequence that is self-monitoring to assure that all preconditions are met and that the required switching and control functions occur properly. On Bipole 2 the dc line voltage is limited to match that of Bipole 1 and sufficient tap change range is provided to permit operation at nominal firing angles.

The sequencing required to parallel two poles is summarized by the steps listed below.

1. Switches are closed connecting the two inverters, one running with current = I_d, and the other with current = 0.
2. The paralleling controls at each inverter are enabled and a special circuit in each bipole averages the total current order to force sharing of the current between the two inverters ($I_d/2$ each). This provides starting current for the newly connected inverter. A precondition for parallel operation is that the current I_d must be greater than 1100 A which roughly corresponds to the sum of the minimum operating currents for the two bipoles.
3. Switches connecting the two rectifiers are closed.

4. Firing control of the newly connected rectifier is released and its current order is increased to a value determined by its power controls.
5. The current averaging circuit is disconnected to allow the corresponding rectifier and inverter currents to be proportional.

The time period from the initiation of the parallel sequence until full restoration of power in both paralleled poles is approximately 300 ms.

One special feature of the paralleling sequence is the precharging of the rectifier stations. Studies showed that preinsertion resistors were not necessary for switching, but to minimize valve stresses the rectifier station is precharged (alpha = 110^o in Bipole 1; alpha = 78^o in Bipole 2; variations due to differing valve technologies) to produce a valve side dc voltage prior to connection. This is not required at the inverter because the physical arrangement of the valves is such as to conduct incoming surges while in a force retard state. Hence the switching surge at the inverter is always low.

In general terms, the special paralleling pole controls are necessary only to facilitate the connection and disconnection of the parallel circuit. During steady-state operation the two bipoles function independently such that, for example, a change in the power produced by the Bipole 1 rectifier is only reflected as a power change at the Bipole 1 inverter. There is no steady-state change in the power at the other stations. Once steady-state parallel operation is achieved, the only real difference between the multiterminal condition and two terminal operation is in the operation of the protective functions and in the consequences for dc system faults.

Deparalleling Sequence

For a scheduled manual deparalleling of the bipoles, the steps can be simplified as listed below.

1. In order to avoid a loss of power during the sequence, the operator makes certain that the power order is less than 0.5 pu on the bipole containing the pole to be isolated. The operator then initiates the deparalleling sequence which automatically controls the remaining functions.
2. The dc voltage setting is lowered at the rectifier that is to remain in operation such that its voltage controller takes it out of current control thereby forcing all other stations into current control.
3. The firing angles are force retarded in the pole to be deparalled to eliminate the station currents. It is important to assure zero current in this manner because the line paralleling switches are high-speed air blast type with no dc current breaking capability.
4. The rectifier and inverter of the pole that is to be isolated from the line are disconnected.
5. The rectifier voltage controller in the running pole is reset to allow the rectifier to regain current control. The time required to complete this sequence is approximately 300 ms.

Emergency or fault deparalleling takes into consideration the potential possibility of temporary blocks caused by consequential arc-backs of the mercury arc valves in Bipole 1. For faults involving a single group in Bipole 1, there is a 700 ms delay of the initiation of the fault deparalleling sequence to allow the recovery of the voltage from a temporary block (400 ms). During this time, parallel operation continues at reduced voltage. For valve group faults in Bipole 2, there is no delay in the initiation of fault deparalleling. The sequence is:

1. Force retard is applied to both of the paralleled poles (all rectifiers and inverters) to completely interrupt the flow of current.
2. The line switches of the faulty pole are opened.
3. Upon confirmation that the switches are open, the force retard is released and normal operation of the nonfaulty pole is resumed.

For fault deparalleling of Bipole 2 (no delay to allow for temporary blocks) the time from fault inception to the recovery of full power on Bipole 1 is about 400 ms.

Operating Experience and Performance

The Nelson River bipoles have operated in parallel for a combined duration of about 36 h, including some overnight continuous periods of 5 h, without any difficulty. During commissioning a few minor control modifications were necessary to improve the system response, but otherwise the systems performed successfully and in agreement with the design concept.

The only significant control modification concerned an 8 Hz oscillation of the inverter currents, which occurred with particular tap changer positions. With the aid of transient computer simulations the oscillation was shown to arise when both inverters were attempting to operate in current error control. Neither inverter could achieve current control because any such transient action conflicted with the current requirement of the other inverter. The problem was resolved by reducing the gain in the current error circuit.

Conclusion

With the successful completion of the commissioning tests, Manitoba Hydro is confident in the ability to operate both of the Nelson River bipoles on the same transmission circuit. The reliability provided by parallel operation exceeds the present requirement because the dc transmission capability of 3669 MW substantially exceeds the current generation level of 2200 MW. However, completion of the Limestone plant in 1992 will add 1330 MW to the generation total, and at that time, Manitoba Hydro will be relying heavily upon the reliability benefits of parallel operation for bipole or even pole line outages.

PACIFIC HVDC INTERTIE EXPANSION PROJECT

Introduction

The original Pacific HVdc Intertie was constructed using mercury arc valve technology in 133 kV series-connected six-pulse groups, with a rating of $\pm$400 kV at 1800 A, for a capability of 1440 MW. The dc transmission line, however, was sized for a current carrying capability in excess of 3000 A. Through study and testing, the system was re-rated to carry 2000 A, for a capability of 1600 MW.

The Pacific Intertie Upgrade Project (Fig. 5) added series connected 100 kV thyristor groups (shown dashed), to bring the system rating up to $\pm$500 kV at 2000 A, for a capability of 2000 MW.

The Pacific Intertie Expansion Project will make use of the previously installed line current carrying capability. One 500 kV 12-pulse converter is under construction in each pole in each station (cross-hatched in Fig. 5). These new converters will be rated at $\pm$500 kV, 1100 A continuous, for a total 3100 MW rating, plus a 1.5 per unit expansion current overload capability for 10 minutes. They will be connected in parallel with the existing six-pulse series groups, using the same dc line and electrodes.

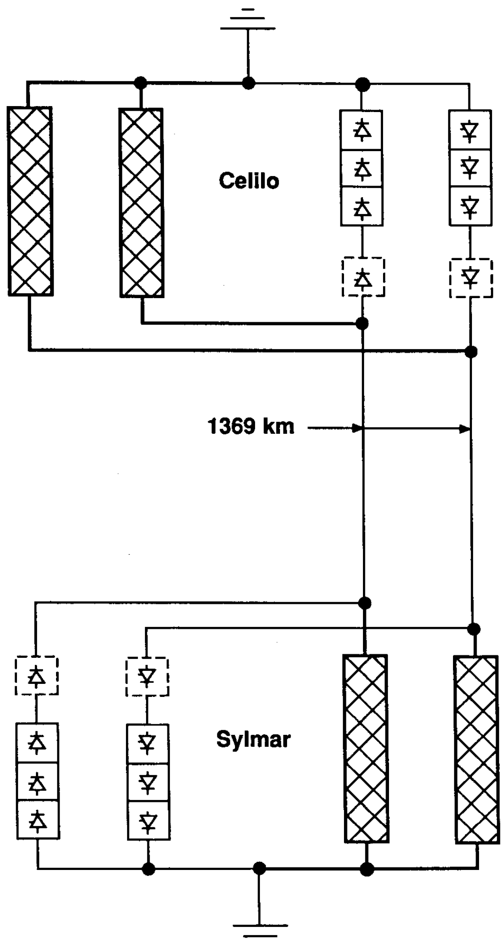

Fig. 5. Pacific Intertie HVdc project as expanded.

At Sylmar, the bushings for converter transformers and smoothing reactors are "through the wall" types because of pollution considerations. A suspended valve design and three-winding transformers are used. The site for the new equipment is physically separated from the old one by a major highway; the two sites are approximately 1 km apart. Other alternatives for expansion were considered, but this one was determined to have the least impact on the existing system during construction and commissioning. The principle of minimum impact on the existing system has been an important concept throughout the design of the project.

Performance Requirements

Three major performance requirements are central to the design of the system:

- Multiple operating configurations,
- Operation without telecommunications,
- Rapid paralleling and deparalleling.

The specification calls for any operating configuration, down to 367 kV, to be possible in parallel operation. For example:

- One mercury arc group off at each end of one pole, resulting in operation at 367 kV on that pole;
- One converter off at one station pole only, leaving the other three in operation at 500 kV;
- One converter and one group off in one pole, leaving the pole in operation at 367 kV at the maximum current capability of the equipment remaining.

For all configurations, pole independence is maintained--that is, a reduction in capability on one pole does not affect the other.

Operation Without Telecommunications

Full manual operation is possible without automatic telecommunications between Celilo and Sylmar and between sites at Sylmar. The protective systems of the eight converters are independent and do not rely on the telecommunication system, the integrity of which would have to be significantly increased. An interesting example of this capability is the remote end recovery sequence (Fig. 6), which is similar to others previously proposed in the literature. For an inverter fault on one pole which is not communicated to the rectifier, the rectifier "sees" the loss of dc voltage due to a fault, retards for a pre-determined period to allow the fault to be cleared and the defective converter to be switched off, and then restarts in increasing current steps. By sensing the dc voltage at the time of restart, the rectifier can determine which inverter or inverters are operating, and thus avoid overloading the remaining inverter.

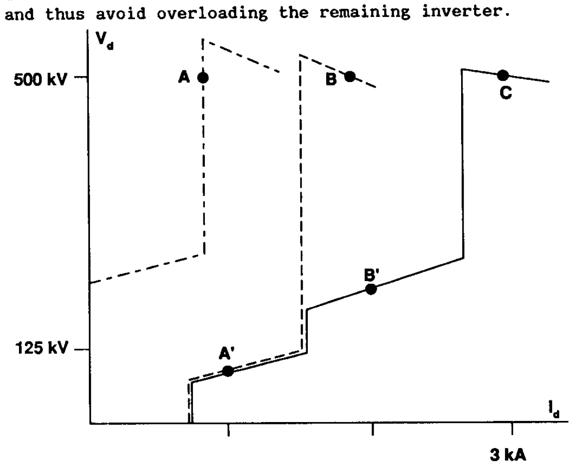

Fig. 6. Operation without telecommunications.

For the remote end recovery sequence, the rectifier initially restarts with a low current. If only the expansion inverter is in operation, the dc voltage will recover to Point A (Fig. 6) and the sequence is complete. If the voltage recovers only to Point A', the rectifier increases the current. If the voltage recovers to Point B, it is determined that only the old inverter is in operation and the sequence is complete. If the voltage recovers only to Point B', the rectifier again increases the current. If the voltage recovers to Point C, it is determined that both inverters are still in operation, and the sequence is complete. If the voltage does not recover, no inverter is present, and the pole shuts off.

Rapid Paralleling and Deparalleling

The rapid paralleling and deparalleling requirement resulted from a desire to maintain constant power flow and inflict as little disturbance on the connected ac systems as possible. It is implemented by using high-speed switches in the higher voltage and neutral sides of both the new and old converters.

Other notable performance requirements include:

- Operators are able to adjust current division "ratios" between converters on a station pole basis in order to avoid undesirable operating points, minimize losses, and limit stress on older equipment. The operator-set ratio is automatically overridden by minimum, nominal, and maximum current limits.
- The loss of one converter is compensated by current increases in other converters.
- The electrode line at Sylmar is not rated for continuous full current and is protected by automatic reductions according to its time/current capability.
- The control system hierarchy has been expanded by the addition of a "Bipole" level to accomplish automatic coordination between new and old converters.

In the event of a fault on the dc side of a 500 kV dc rectifier group's converter transformer, the arrester connected between this point and the 500 kV dc level will be forced to carry the current from the parallel rectifier until that rectifier can be blocked. This necessitates a very rapid detection and block on the order of 10 ms.

If an old converter is switched off, the line segment between the converters (approximately 1 km long) is energized at 500 kV dc. Due to the length and vulnerability of this line, an arrester will be installed on the line side of the disconnect switch of the old converter.

Filtering Requirements

The project specification requires the contractor to design the new parallel dc filters (Fig. 7) so as not to exceed the existing induced noise voltage (INV) level requirements. This means that the INV for this new multiterminal system during normal bipolar operation must not exceed 10 mV/km. The INV for monopolar operation and reduced voltage bipolar operation must be kept below 20 mV/km.

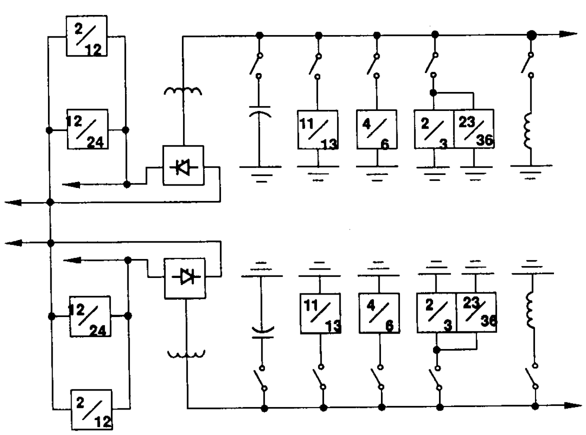

Fig 7. Configuration of ac and dc filters.

The specification also requires the new filters to be designed to prevent the existing and new filters from being overloaded as a result of detuning or resonance conditions during any possible operating mode. Consequently, two double-tuned filter arms will be installed on each pole. One filter arm will be tuned to 2nd/12th and the other to 12th/24th harmonics.

Paralleling of the existing ac filters with new filters raises concerns for filter overloading due to detuning and resonance conditions. The specification requires the filters to be designed to meet an individual harmonic distortion of less than 1.0 percent, a total harmonic distortion of less than 2.0 percent and a telephone influence factor of less than 30. These performance values must be met during parallel and stand-alone operation with any one filter sub-bank out of service and with the most pessimistic imbalance of wye and delta groups at the existing station. The required performance will be achieved by including four double-tuned filter arms for each new converter. The filter arms will be tuned to the 2nd/3rd, 4th/6th, 11th/13th and 23rd/36th harmonics.

Along with the filters, each converter will have a capacitor sub-bank and a shunt reactor to meet the reactive power demands for the converters and the ac system. The shunt reactor is necessary to limit the var exchange with the ac system to ± 100 Mvar. Because of the var deficiency of the existing ac system, 1060 Mvar of filters and shunt capacitors will be installed. The 1060 Mvar together with the 1085 Mvar of the existing station creates a potential for a high dynamic overvoltage condition. In order to meet the filter performance and var exchange requirements and to prevent a high dynamic overvoltage condition, a software-controlled var switching will be installed.

Conclusion

Since the project is still under construction, there have been few transitional difficulties so far.

Expected problems include:

1) Coordination of installation, testing, and commissioning work during the short time period allowed for annual maintenance of the old system. The interconnection period is presently scheduled to be only five weeks, from start of work during maintenance outages to the time when the old system is totally operational again. The commissioning of the new converters, and of new and old in parallel, will extend over about six months.
2) Replacement of old high-speed neutral switches and installation of new high voltage high-speed switches.
3) Replacement of several parts of the old control system, and integration of new and old control systems.

Problems with coordinated fault recovery, the dynamics of the paralleling and deparalleling sequence, and control modes of converter current and voltage are currently the subject of a simulator study.

SARDINIA-CORSICA-ITALY (SACOI) SYSTEM TAPPING

Introduction

Since 1967, the power networks of continental Italy and Sardinia have been connected by a monopolar dc link (SACOI). This link is rated for 200 MW at 200 kV and follows the eastern coastline of Corsica as an overhead line. Two pairs of submarine cables connect the mainland of Italy to Northern Corsica and Southern Corsica to Sardinia respectively (Fig. 8). To compensate for the passage of this overhead line, the initial agreement between Electricite de France (EDF) and its Italian counterpart, Ente Nazionale per l'Energia Elettrica (ENEL), provided a security of 20 MW tapping on this link as soon as technically feasible.

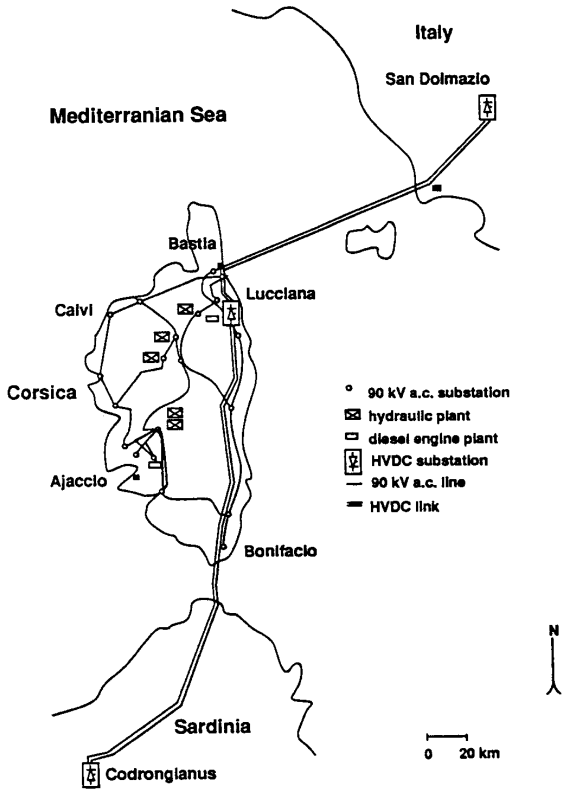

Fig. 8. SACOI multiterminal dc link.

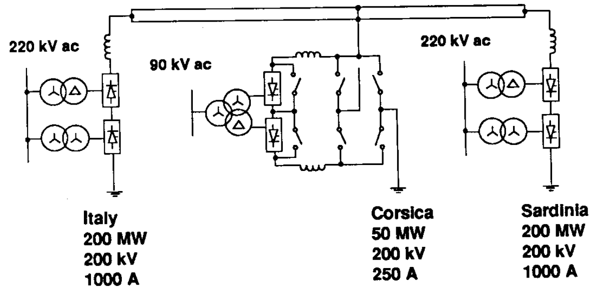

Fig. 9. Basic configuration of the parallel tapping.

Parallel Tapping or Series Tapping

The choice of parallel tapping was made for two major reasons:

- Series tapping would have led to a reduction of the dc voltage for the main inverter station. This station is equipped with mercury arc valves and could not operate with the large extinction angles imposed by series tapping,
- To assure 20 MW in Corsica, the Lucciana station had to be rated for the following current-voltage characteristics: 100 A/200 kV and 1000 A/20 kV. The main link is operated to control the frequency of the Sardinian network and, therefore, can rapidly vary its current between the limits of 100 A and 1000 A. The series tapping alternative would have led to a Corsican converter station rating of 200 MW.

Parallel tapping requires the use of two pairs of fast-reversing switches to adapt the connection of the Corsican station to the line polarity and to the selected direction of power flow (Fig. 9)

Although the power guaranteed by ENEL is only 20 MW, the station was rated for 50 MW since the values of dc voltage and fault current in case of station bypass were such that the investment necessary to increase the nominal current from 100 A to 250 A remained minimal. Weekly agreements between Corsican and Sardinian dispatching define the maximum power to be imported in Corsica (from 20 MW to 50 MW) for every day of the week.

Current Control Operation

Simulator tests [11][12] proved that only current control operation of the Corsican station allowed stable operation of the station. The low values of short circuit capacity available at Lucciana (down to 150 MVA) do not permit the station to control dc voltage without stability problems. Moreover, local current control eliminates the need for a central current order balancer as well as specific means of telecommunication with the main stations.

In the event of ac voltage drop, the Corsican station tends to lose the current control, which leads to a substantial increase of this current in inverter operation, at least equal to the current margin of the main link (about 200 A). This situation leads almost inevitably to a commutation failure and, consequently, to line bypass. This failure is cleared by the line protection of the main rectifier which interrupts the current on the whole link for about 300 ms and releases the bypass pairs in Corsica. Then the power flow can resume normally between the Italian stations, whereas the Corsican station can resume the exchange only after the dc and ac voltages have recovered.

In order to reduce the frequency of occurrence of commutation failures on the link, a value of 40^{o} has been selected for the extinction angle; this permits the Corsican station to keep current control for ac voltage dips of 20 percent. Thus the commutation failure occurrence probability remains less than one per week. However, this high margin angle value leads to a substantial var consumption (1 Mvar per converted MW). Therefore, five filter banks, each rated for 10 Mvar, are necessary for local var compensation in nominal operation.

Frequency Control of the Corsican Station

The Corsician station contributes to the primary and secondary frequency controls through two regulation loops:

- The first is a proportional loop limited in amplitude to ± 5 MW, which reduces the fast stresses on the groups of the network due to the natural frequency fluctuations,
- The second is an integral loop which adjusts the power level of the station to control the average frequency to exactly 50 Hz.

Overriding this regulation, an "emergency" loop can vary the power by a predetermined value in the event of the loss of a generating unit on Corsica. Switching into this mode (called "spinning reserve") is based on a local criterion of frequency threshold and derivative. The action of this loop can also lead to the automatic shutdown of the station in rectifier mode and possibly to the automatic restarting in inverter mode after the operation of fast reversing switches.

The considerable frequency fluctuations liable to occur in the ac system have led to specifying the station operation between 40 and 55 Hz with rates of fluctuation of 4 Hz/s in this range.

Response of the Station to AC Faults

The station was designed to tolerate up to 20 percent voltage reductions from ac faults. Figure 10 shows a site fault test for which the amplitude is sufficient to make the Corsican station lose current control but the duration of which is insufficient to result in a commutation failure. Other tests were carried out in both rectifier and inverter operation and showed the satisfactory response of the station to faults occurring near the station in the 90 kV network.

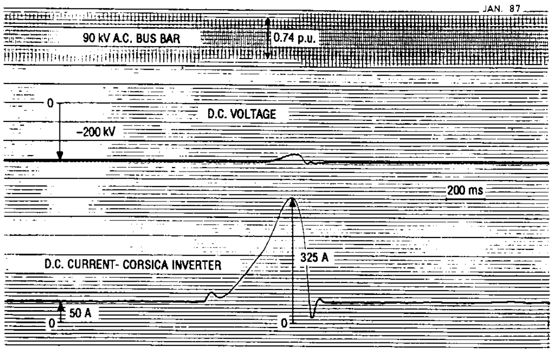

Fig. 10. AC fault without commutation failure.

Project Coordination

The feasibility studies were carried out mainly on the EDF dc simulator and defined the major sequences characteristic of the operation of the multiterminal link. At the same time, a study was seconded to the constructor of the existing link, which brought quite similar results. An additional manufacturer was studying the feasibility of the Corsican station. These multiple study activities reinforced the credibility of the technical solutions proposed by EDF.

The second stage consisted of thoroughly analyzing the operating sequences of the existing link in order to harmonize the behavior of the Corsican station, to avoid any incompatibilities between the protections of the various stations, and also to investigate the problems related to the coordination of dc current orders. Those problems were analyzed and solved by an EDF-ENEL Working Group; the implementation of the modifications of the control system of the main stations was seconded to the original manufacturer. These developments essentially concerned current order coordination. This stage required a significant time investment to achieve compatibility with the original link after more than 20 years.

Considering the complexity of the control system vis-a-vis many possible operating configurations and sequences, the commissioning was preceded by the checkout and adjustment of the control equipment on the EDF dc simulator. However, to enable the Corsican network able to use the station during winter 1986-87, the commissioning took place in two stages as indicated in the program in Fig. 11.

The following points should be noted particularly:

- The simulator tests had a total duration of 6 1/2 months,
- The EDF-ENEL link tests had a total duration of 3 1/2 months.

The durations are quite long compared to the typical times for commissioning a point-to-point link. Moreover, the periods when the link was tested

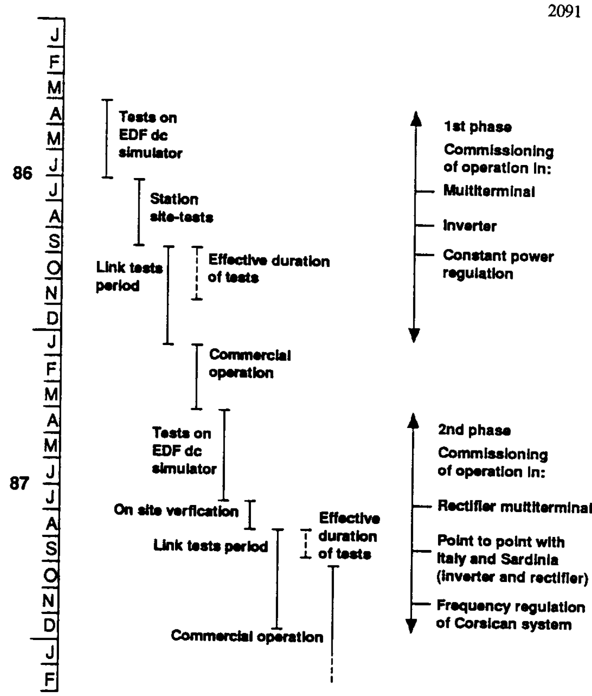

Fig 11. Commissioning sequence in two stages.

were seldom favorable for the Sardinian and Corsican network and, therefore, numerous operating constraints led to double the actual duration of this series of tests.

Conclusion

Economically speaking, the solution of power tapping of the SACOI link for partial supply of Corsica proved quite attractive, but it also proved to be a technical success as far as the results of site tests and the first months of operation are concerned. Such satisfactory results largely rest on the knowledge acquired during the basic studies carried out between 1970 and 1980 which are at the origin of the general control and protection principles that have been implemented for the SACOI link. This first case of a real dc interconnection between three networks geographically and electrically isolated will certainly reinforce the credibility of the multiterminal solution for power systems planners.

THE HYDRO-QUEBEC - NEW ENGLAND FIVE TERMINAL 450 KV DC SYSTEM

Introduction

In March of 1983, New England Power Pool (NEPOOL) member utilities entered into a formal agreement with Hydro-Quebec to purchase 33 terawatt hours (TWh) of surplus hydroelectric energy over an eleven-year period beginning in 1986. To provide a means for delivering this energy, the construction of certain dc facilities was proposed. These facilities, referred to as the Phase I facilities, include a 172 km ± 450 kV dc transmission line from a site near Sherbrooke, Quebec to a site adjacent to the existing Comerford generating station in the town of Monroe, New Hampshire and two converter terminals at the ends of the dc transmission line, known as Des Cantons and

Comerford. The two-terminal 690 MW HVdc system was placed in commercial operation on October 1, 1986.

NEPOOL, on behalf of its member utilities, subsequently reached an agreement with Hydro-Quebec for the purchase of an additional 70 TWh of guaranteed energy over a ten-year period currently scheduled to begin in 1990. The Phase II facilities will transmit this additional hydroelectric energy from the La Grande generation complex to load centers in southern Quebec and central New England. The Phase II system (Fig. 12) will ultimately consist of five converter terminals, three in Quebec and two in New England. The three new converter terminals are: i) a 2,000 MW converter terminal at the Radisson substation near the La Grande no. 2 generating plant, ii) a 2000 MW converter at the Nicolet substation in southern Quebec, and iii) an 1,800 MW converter terminal near the Sandy Pond substation in Massachusetts [13].

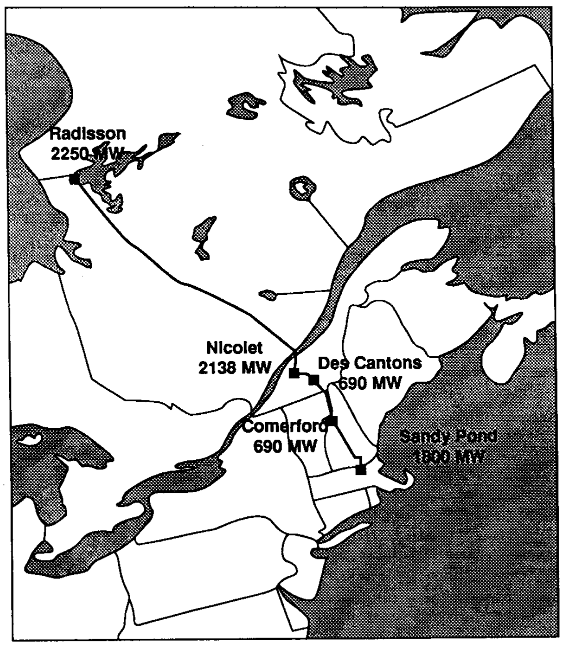

Fig. 12. Hydro-Quebec NEPOOL Phase II interconnection.

A multiterminal dc system makes it possible to satisfy the following Hydro-Quebec and New England requirements:

a) The need to increase the energy import capability into New England,
b) The fact that the interconnection must be asynchronous,
c) The necessity to be capable of permanently isolating up to 2,000 MW of generation on the New England system, and
d) The need for Hydro-Quebec to add 2,000 MW of transmission capability by 1992 between the James Bay area and the load centers of the province.

Geographical considerations have played a determining role in the choice of the existing power transmission technique and general layout of the Hydro-Quebec network. The most important factor is the fact that almost 100 percent of the generation is hydroelectric. Currently, some 70 percent of the available generation originates from sites located at distances varying from 600 km to 1,200 km away from the major load center, in the Montreal area. Two large areas are involved. The first one at James Bay in the northwestern part of the province accounts for about 45 percent of that remote generation (10,000 MW, 1,000 km away from Montreal). The second one in the northeastern part of the province includes about 12,000 MW of generation distributed at distances varying from 600 km to 1,200 km from Montreal.

On the other hand, about 80% of the total system load is located in the area between Quebec city and Montreal, some 250 km apart. The very large distance between the two remote generation areas is such that no direct interconnection between them was practically possible. As a result two major radial 735 kV ac networks were developed, each carrying a maximum of about 10,000 MW on its more loaded section and the two being interconnected in the general area of Montreal - Quebec city as well as at a location some 200 km north of Quebec city.

Reliability Aspects

The availability of large amounts of surplus hydroelectric generation has proved to be very useful in the context of the North American energy supply. When it became clear that the Hydro-Quebec system load would increase at lower rates than was originally forecasted, significant amounts of that hydroelectric energy could be made available at lower costs than the operating cost of fossil fuel power plants used in the northeastern part of the United States. Over the years, it has become increasingly beneficial for Hydro-Quebec and the neighboring utilities to engage in interconnection conventions and more recently to sign firm energy sales contracts.

Because the Hydro-Quebec transmission system was not designed to handle a synchronous tie with a large interconnected system many times its size in terms of installed generation, dc interconnection ties are required and provide the cheapest solution to allow large scale export.

With the increasing capacity of dc interconnections, a concern appeared among utilities in the northeastern United States about the possible effects on system security due to the loss of those ties. Instability of the Hydro-Quebec system resulting in the loss of all dc ties is considered a probable event and must be dealt with in a stringent manner.

The concern has become a serious issue because of the planned increase of the interconnection between Hydro-Quebec and NEPOOL from 690 to 2,000 MW in 1990. This will bring the total dc interconnection ties to 3,900 MW. However, under most operating conditions the maximum acceptable simultaneous loss of power imports into the interconnected system of the northeastern United States is limited to approximately 2,000 MW. Because of this constraint, the Phase II design is required to ensure that in the event of a Hydro-Quebec system collapse, the interconnection will remain unaffected. Conversely, a fault on the multiterminal system must not affect the remaining interconnections.

The Multiterminal HVDC System

To solve the problem, Hydro-Quebec agreed to depart from its planned system expansion at 735 kV and decided to extend the 450 kV HVdc line from the Phase I interconnection to the James Bay area. Practically speaking, the construction of this new line is advanced by two years in order to suit the needs of the interconnection. By adding a 1,800 MW converter terminal at Sandy Pond, New England will have the ability to increase the energy import capability from Quebec. The addition of the Nicolet converter station in 1992 will transform the northern section of the dc line into the sixth line of the James Bay transmission system and allow the 2,000 MW of hydroelectric peaking power added at LaGrande 2 (LG 2) in 1992-93 to be transmitted to the load centers in southern Quebec.

Figure 13 shows the stages of construction of the multiterminal system as well as line lengths and converter ratings. When completed, the multiterminal system will provide the operating flexibility of being able to switch smoothly back and forth from the export mode to the transmission of energy within the Hydro-Quebec system or to operate in both modes simultaneously.

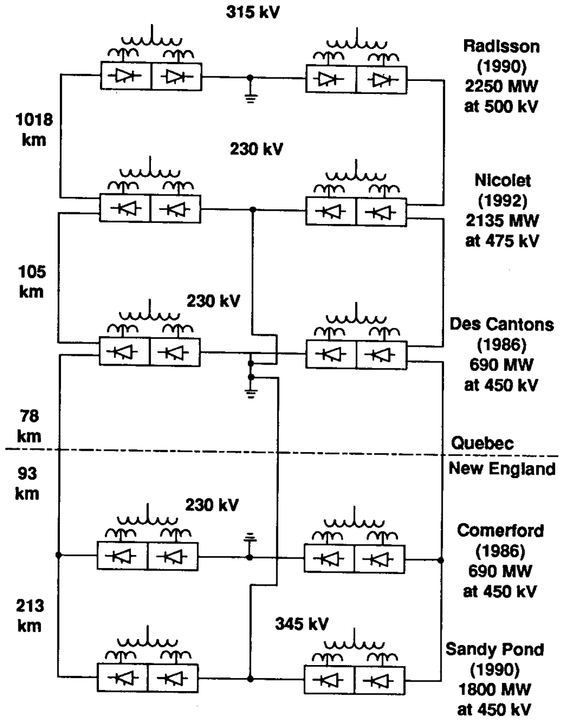

Fig. 13. Five-terminal system configuration.

Control and Performance Aspects

The most salient features of the multiterminal control functions are:

a) Generation can be isolated from the Hydro-Quebec system,
b) The expected recovery time of the larger terminals following a large perturbation is of the order of 100 ms for two-terminal operation and 200 ms for multiterminal configuration,
c) No dc breakers are used; all fault recovery sequences are realized through control action.

Most of the classic two-terminal control and protection functions are used at the local converter level. New functions had to be developed at the master control level.

The current margin control principle is used with the inverter operating at the largest power level acting as the voltage setting terminal (VST) [14]. When Hydro-Quebec is exporting to New England, the VST is Sandy Pond. Regarding the choice between Radisson and Sandy Pond as VST, it must be noted that frequency control of the generators at Radisson is required at all times, even without telecommunications. It is easier to fulfill that requirement if Radisson is in current control.

Following the loss of telecommunications, transmission of power must be reestablished even following the loss of a converter station. The resulting transmission level must be predictable, stable and within the ratings of the remaining converters. This is accomplished through proper coordination of the voltage dependent current order limiters and their release time constants. The technical specifications called for sufficient range in the converter controls such that a 5 percent change in ac or dc voltage will not cause a mode shift in control operating points. Similarly, a sudden change in the ac voltage of 10 percent on all three phases or of 30 percent on one phase must not cause a commutation failure.

A large number of configurations must be considered in the design of the master controller because the five stations and the line sections can be combined in many different ways. Fortunately, simplifications are possible. For example, the Radisson converters will always operate as rectifiers and will have fixed connections to the dc line. The two stations in the Montreal area, Nicolet and Des Cantons, will both be provided with switches to make power reversal possible without changing the polarity of the line voltage. Being a relatively small converter connected to a weak ac system, Comerford will only operate with Des Cantons in two terminal mode. This provides the ability for New England to continue to import power during scheduled or unscheduled outages of the Radisson or Sandy Pond converters.

The system will also be operable as two separate and independent dc networks: one for power transmission within Quebec (Radisson to Nicolet) and the other for the exchange of power between New England and Quebec. There will be two master controllers, one at Radisson and the other at Sandy Pond. In split network operation, both units are used, one for each HVdc network. However, in multiterminal configurations, one will be in lead control with the stand-by unit being continuously updated.

The master controller must make sure that the sum of the rectifier current orders is equal to the sum of the inverter current orders. Figure 14 gives the basic schematic for this function. The K weighting factors in the feedback loops reallocate any current order imbalance according to predetermined criteria. Different criteria can be selected according to dc system configuration, operating conditions, etc. Current order limits are generated locally in each converter station. Overload capability of the new converters (Radisson, Nicolet and Sandy Pond) will be exploited during dc power modulation.

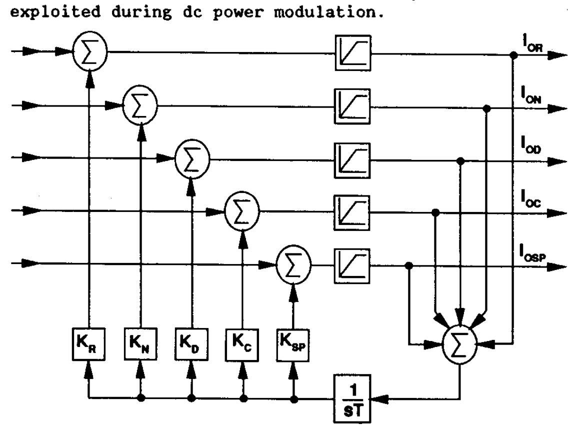

Fig. 14. Current order balancing.

The master controller allows the operation in terms of power orders. However, because of the losses in the dc system, balanced power orders do not correspond to balanced current orders. It must be possible to refer the losses to a predetermined converter station. Time coordination of ramping of power orders is also a special function in a multiterminal system. For example , if two converter stations are assigned to compensate for a change of power order at an inverter, the three power orders may be ramped at different speeds to reach the final levels at the same time. Coordination of the ramping must also respect the maximum allowable ramping speed of each station involved.

In a multiterminal system, depending on the initial configuration and load flow, a number of post-fault configurations and load flows may be possible for the remaining dc system. After removal of the faulty element, the recovery takes place in two steps. First, the master controller determines a new load flow based on a preset recovery criterion selected according to pre-fault operating conditions in both ac networks as well as in the dc system. In that initial recovery, the presence of ground current is acceptable. In the second step, called reconfiguration, the ground current must be removed. The master controller assists the operator by presenting new configurations which eliminate ground current.

There exist two types of frequency control. The first is a dead-band frequency control (proportional action) that modulates the power flow to New England in order to prevent LG 2 generator tripping because of excessive speed deviation. This control acts transiently while the speed governors of the units readjust the generation to the scheduled export level. The second is a steady-state frequency control in the isolated mode performed by the speed governors of the generating units. It can be supplemented by an integrating feedback control at the converters.

When the Comerford converter station is operated at a high load level, the nearby small hydro generating units are near their steady state stability limit and there is a need for stabilization. Local power modulation control will act only on the negative half cycle of the power oscillations by reducing the power to Comerford. The surplus power during this modulation action will be taken by the VST. Hence this control does not require telecommunications.

Integration of Controls from Different Suppliers

Different suppliers are involved in Phase I and Phase II. In fact, the Phase I installations had not been designed for the final Phase II configuration.

In order to i) minimize the duration of the shut-down period, ii) maximize the compatibility of subsystems and iii) provide the special multiterminal control functions, it was decided to implement the integration of Phases I and II in the following manner:

a) The existing converter and pole control systems will be replaced. However, the reactive power controllers, the valve controls, the thyristor monitoring systems and the valve cooling controls will be maintained.
b) The existing dc protection systems will be replaced and new dc bipole protections will be added. The ac protection systems will be maintained.
c) The existing monitoring equipment will be maintained and the alarm points from the new controls will replace the alarm points from the existing controls.
d) The existing operator control panels will be utilized for control of ac and dc switches and metering. A new mimic panel section will be installed for control of the new dc switches and local control functions.
e) The main interface points between the new and the existing equipment will be existing interface cubicles and the generator of optic firing pulses in the existing valve control cubicles. New dc measuring interface and dc switch interface cubicles will be added.

Conclusion

An agreement for guaranteed energy purchase led to a decision to expand the Phase I two-terminal Hydro-Quebec - NEPOOL HVdc interconnection into a five-terminal system bringing power from James Bay to southern Quebec and New England. Because of the many possible operating configurations, a complex control and protection system is required. The system can operate as two independent dc networks, one for power transfer within Quebec and the second for the exchange of power between Quebec and New England.

CONCLUSIONS

Four practical multiterminal dc systems have been described in this paper. Two are presently in commercial operation: Nelson River (double-bipole four-terminal) and Sardinia-Corsica-Italy (two-terminal monopolar tapped to become three-terminal). Two others are expansions of existing systems and are under construction: Pacific HVdc Intertie (bipolar four-terminal) and Hydro-Quebec/New England (bipolar five-terminal).

All of the systems are able to shift to a stable operating point following a disturbance (e.g., loss of a converter station). In the absence of telecommunications, this means that the new configuration must be achieved automatically. This can be done using the current margin control principle, for example, whereby alternative operating points are available depending on the dc voltage of the system. Protection is achieved through fast control action; no dc circuit breakers are employed.

These four multiterminal dc systems illustrate that the design of such systems is application-dependent. The technical community awaits with interest the arrival of performance data and availability statistics.

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Discussion

Allan Greenwood, (Rensselaer Polytechnic Institute Troy, NY):

It is a sad commentary that a paper on Multiterminal DC Power Transmission, more than eleven pages in length, devotes only five lines to HVDC circuit breakers, and that these lines were dismissive, reflecting a skeptical point of view. What is this "uncertain reliability" of HVDC breakers to which the authors refer? There is no reference to which the reader can seek confirmation. Field testing of HVDC circuit breakers at 400 kV was reported in 1985 [1] for both airblast and SF_6 technologies. Data on successful laboratory tests at 250 kV, 8 kA [2] was published the same year, while breakers for lesser voltages, using oil and vacuum, were tested in 1976 [3] and 1972 [4]. Quoting from reference [3], "Emphasis was placed on using mainly already existing, well-tried and reliable power equipment". Referring to the passive commutation circuit used more recently for a 500 kV breaker, the authors state [5], "A decisive advantage of such a circuit for practical applications is that only well known components are employed".

It used to be that inquiries concerning HVDC breakers was met with a statement that there was no need for such devices since all HVDC systems were two terminal. At the same time, if one asked why multiterminal HVDC systems did not exist, one was told that it was because there were no HVDC circuit breakers. It is surely time to move beyond this circuitous logic and take advantage of the healthy synergism that breakers and converter controls can provide. Let us not be told that these developments must await more experience. If the industry had waited for more experience of solid state devices in 1972, it would still be installing mercury arc converters.

CIGRE has had a working group on HVDC Switching Equipment for almost twenty years. Some time ago it became a joint working group (13/14.08) between Study Committee 13 (Switching Equipment) and 14 (DC Links), with a strong representation of both switchgear and HVDC systems people. The Working Group has published many reports. Of specific relevance are "Circuit Breakers for Parallel Tapping of HVDC Lines," [6] and "The Current Commutation Function of HVDC Switching Devices," [7]. The members will shortly be addressing the subject of HVDC circuit breakers for meshed systems. Contributions to this work would be welcomed by the writer.

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Manuscript received August 1, 1989.

H. P. Lips, (Siemens AG, Erlangen, Germany): I would like the authors to expand on the following items.

1. On page two, it is implied that d.c. breakers are more complicated and have an uncertain reliability compared to other switching alternatives. This statement seems somewhat surprizing in view of the full-size field tests performed by BPA and using an a.c. breaker of accepted reliability as the main switching element, complemented by passive circuits. No check-back signals and corresponding interlocks were needed as are required for alternative switching arrangements.
2. One interesting aspect of the Pacific Intertie Expansion is that this system had to be designed around the a.c. and d.c. filters of the existing station on the same bus. The authors have given the specification criteria and the selected filter configurations. A similar situation is expected to have occured on the Nelson River Bipole 2 system. Would the authors please comment on the operating results, i.e. how the measured performance on these systems agreed with the design objectives.

Manuscript received September 25, 1989.

D. J. Melvold, Department of Water and Power, Los Angeles, California: In the past, most publications on multiterminal hvdc systems have been theoretical in nature and considered the "ideal" system which starts out as a multiterminal system. However, it is more likely that, as with ac systems, most multiterminal systems will evolve from point-to-point systems. Therefore, a critical, practical concern is the adaptability or flexibility of dc systems to expand. This paper deals with four systems -- two of which may never have been anticipated at the outset to be expanded (at least not in the fashion they eventually were).

The Pacific HVDC Intertie System was originally planned in its conceptual stage as a three-terminal system with three interconnecting dc lines in a triangle system configuration. A third terminal, to have been located at Mead, was never built. However, during its final design and actual construction, only the conductor size of the dc line incorporated any accommodation for expansion to the three-terminal system.

It would be beneficial for the readers to have some detailed information on what equipment -- main circuit components, controls or auxiliaries -- had to be replaced, modified or simply discarded in the original terminals to accomodate the expansion to the multiterminal system. Of course, some components may simply have been replaced, etc. due to normal retirement or due to lack of space requiring compaction of the original station apparatus so as to accomodate new equipment for the expansion.

It is my understanding that Nelson River I and Sardinia were originally specified to be expandable at a later stage to the multiterminal systems described in the paper. The question here is three-fold: Was the original design foresighted enough to accommodate the later expansion as originally thought? Was any equipment replaced, modified or simply discarded that was not expected to be? What affect did advancements in technology have on the original plans for expansion?

Regarding the Hydro Quebec-New England system, was the five-terminal system originally envisioned, and was expansion to such made a requirement of the original Des Cantons-Comerford design? Again, what equipment had to be replaced, modified, or simply discarded? Of that, how much was the result of improvements in technology? How much was due to the choice of a different supplier on Phase II?

In each case, what did the utility learn from the expansion that they would have done differently in the original "non-multiterminal" system to better accommodate expansion at a later time or to minimize either total equipment costs (i.e., equipment for the original plus expansion) or outage time for expansion construction?

Answers to the above questions would be invaluable to the industry and especially to utilities contemplating dc in a long-term staging plan.

Manuscript received August 7, 1989.

M.S. Holland: The measured AC and DC filter performance did not meet all design objectives at Sylmar. AC filter performance measurements indicated that the specified maximum TIF was met. In general, the total harmonic distortion (DT) values were much higher than calculated design values. However, the DT did not exceed the specified design maximum. The individual harmonic distortion was 1.1% at the 5th harmonic, exceeding the specified limit of 1.0%. High values of 5th and 7th harmonic were not foreseen in the design calculations, which showed the 11th harmonic to be the highest, at 0.09%, and almost no 5th harmonic.

During commissioning a high level of harmonics was discovered on the AC line between old and expansion sites indicating the harmonics generated at one site are flowing to the other's AC filters. The expansion AC filters seem to be taking the old converter harmonic current as well as expansion harmonic currents. This does not result in overload, but does create telephone interference problems in the immediate area.

DC filter performance measurements show that the induced noise voltage level was higher than the calculated design values in all cases. The specified maximums were exceeded in four modes:

Mode	Measured Level (mV/kM)	Calculated Design (mV/kM)	Specified Maximum (mV/kM)
parallel, bipolar, 500kV	27.1	10.0	10.0
expansion, bipolar 500kV	19.3	5.0	10.0
expansion, bipolar, 367kV	15.4	8.0	10.0
expansion, monopolar metallic return, 500kV	64.4	19.0	20.0

Separately, during commissioning a resonance condition at the 24th harmonic was found at Sylmar between the old 6th harmonic filter, the DC line between the old and new sites, and the 12/24th harmonic filter at the expansion. The design study did not include the line impedance between the sites. The resonance has been reduced by detuning the expansion 12/24th filter, thus reducing the level of 24th harmonic.

Some equipment was replaced or modified to accommodate the expansion of the Pacific intertie.

The neutral bus overvoltage protection scheme, previously composed of varistors, relays, and shorting switches, was replaced with modern arresters, and the low voltage load break switches, used to isolate the converter neutral in the event of a fault, were replaced, both in response to the higher energies present in the new system.

The power supply for the control systems in the old station at Sylmar was enlarged, via replacement of batteries and chargers, to feed additional hardware. Supplemental air conditioning had to be added in the old control room to offset the load added by this hardware.

Approximately 185 transmission line towers had to be raised to accommodate additional conductor sag caused by the increased current of the expanded system. The overhead conductors of the electrode line at Sylmar were retensioned.

There are large software changes in the top level of the control system. Other control systems changes are relatively minor, and some were done to take advantage of the current state of the art, to improve operator interfaces, or to improve the appearance of the control area.

To better accommodate expansion at a later time, had such expansion been anticipated, more area in the yards, especially around the line terminations, could have been provided. Different yard and control room layouts, with thought given to eventual additions, would have been beneficial. Of course, if the eventual equipment ratings were known at the time of original construction, replacement of underrated equipment would not be required.

J. LeMay and D. J. Lorden: In reply to D. J. Melvold, Phase I of the Hydro-Quebec - New England interconnections was commissioned with provisions for an expansion to a three-terminal system by extending the dc line some 200 km southward from Comerford, to a new converter station at Sandy Pond, and by increasing the rating of Des Cantons to 2000 MW with parallel converters. The provisions consisted almost exclusively of space in the yards. However, as described in the paper, ac transmission system reliability aspects led to the decision to extend the dc line to the James Bay area, more than 1100 km north of Des Cantons, instead of the planned increase in capacity at that station.

Although the Phase I installations had not been designed for the final Phase II system configuration, the integration of the old into the new involves no equipment replacement except for the converter and pole controls and for the dc-side protection systems, as described in the paper. Additional equipment at Des Cantons include dc-yard switching for routing the dc line in and out of the station, for sectionalizing the multiterminal system into two separate subsystems and for the inversion of the converters without changing the polarity of the dc voltage. Additional dc filter equipment and line-side smoothing reactors were required at both Des Cantons and Comerford mostly to meet the more stringent Phase II requirements.

The voltage rating of neutral equipment at Des Cantons and Comerford imposes operating constraints such as the choice of the grounding location in metallic return mode and the sequence of switching between metallic return and ground return. These limitations are deemed acceptable because these operating conditions are not expected to occur frequently.

Our practice to date has been to provide space but to minimize capital investment for future installations. This way, the utilities can profit from the advance in technology and give more flexibility to the supplier of the latter installations. Outage time for construction and commissioning of the new installations can be minimized if the specifications for the initial installation include requirements for clearly defined interfaces such as control panels, expected physical layout of future equipment, etc.

In reply to H. P. Lips, without questioning the reliability of dc breakers, we would like to state that the transient performance requirements for the Hydro-Quebec - New England multiterminal system did not exclude the use of dc breakers. Recovery times, commutation failure performance and other ac-dc interaction aspects were specified based on the results of feasibility studies performed using the dc simulator and digital stability programs. One of the conclusions of those studies is that if a dc breaker is used to isolate a faulty converter in a multi-location multiterminal system such as ours, a centralized current order reallocation is still required to avoid commutation failure at the other inverter(s) because of the sudden change in operating conditions.

The supplier of the converter stations has implemented a solution whereby the faulty converter is switched out under no-voltage and no-current conditions (phase retard of rectifier). Restart of the remaining converters on the faulted pole is always performed under controlled conditions, whether the event involved a dc fault or a commutation failure only.

W. F. Long: Professor Greenwood would prefer that the paper include more information on dc circuit breakers. This would be at variance with the topic which the paper addresses, namely application aspects of four operating multiterminal systems. The intent of the panel session and subsequent paper was to illustrate the fact that practical multiterminal dc systems are here and are in operation. To devote time and space to dc circuit breakers, when none are employed on these systems, would be incongruous.

The comment on "uncertain reliability" refers to the limited field experience with the devices. As Professor Greenwood points out, field and laboratory tests have been successful. However, no prototype has been installed in an operating environment (save for low-voltage metallic-return transfer breakers). It is this lack of operating experience that fosters the skepticism. This author would strongly encourage a utility/manufacturer/funding agency to install a test bed for a dc breaker, preferably at a weak inverter on a three-terminal system.

Manuscript received September 25, 1989.