EXHIBIT A

MEMO from the Desk of

ROBERT H. HARTLEY

2-11-80

Dear Mike:

This is in preparation of our meeting of February 20 and 21.

Best regards.

8004210394

DP-6310-NG1-TE January 29, 1980

Nuclear Regulatory Commission

The term "intraregional interconnections" means the interconnections between various operating electric utilities companies within a region.

The term "intraregional interconnections" within the ERCOT Reliability Council would include the interconnections between North TIS and South TIS and would basically apply to the existing 345 interconnections between those members.

Interregional interconnections are those transmission lines which interconnect one region to another such as connections between the Southwest Power Pool (SPP) and the Southeast Reliability Council (SERC).

No.

Exchanges between utilities that are indirectly interconnected are called third party transactions and are normal within the industry.

Region-to-region or pool-to-pool interregional transactions can occur between utilities in different regions. Such transactions can consist of economy exchange, emergency exchange, maintenance exchange, firm purchases and sales, interruptible energy, operating reserve exchange, spinning reserves, mutual standby reserves, etc.

Presently high voltage and extra high voltage interconnections exist in seven Reliability Councils: the Southwest Power Pool (SPP), the Mid Area Continent Reliability Coordination Agreement (MARCA), the Mid America Interpool Network (MAIN), the Southeastern Electric Reliability Council (SERC), the East Central Area Reliability Coordination Agreement (ECAR), the Mid Atlantic Area Council (MAAC), and the Northeast Power Coordinating Council (NPCC). These seven reliability council regions have interconnections at 345 kV, 500 kV and 765 kV. The Western Systems Coordinating Council (WSCC) does not interconnections with these seven regions other than through a single DC intertie known as the Stegaltie. The Electric Reliability Council of Tex (ERCOT) does not have such interconnections with other reliability councils.

Within the capacity of the interconnections between regions there are also emergency transfer capability values.

The Exhibit entitled, "Major EHV Transmission Lines", dated 12/31/76 gives a visual guide to the interconnections being referred to. Much of the interconnection capacity shown on this exhibit is being used for normal inter-, intra- and multiple-region transfers. It is not known how much of this capacity is being used for normal transactions. However, lying on top of the normal transactions are non-simultaneous emergency transfer capabilities. These values have been determined by the NERC multi-region transfer subcommittee and the results are published. However, during the 1978 coal strike the transfer capability was demonstrated as per page 14 of the Eighth Annual Review of NERC. The region-by-region non-simultaneous emergency transfer capabilities from that report are as follows:

ECAR to MAAC - 3,500 MW to 5,500 MW in 1982

MAAC to ECAR - 2,300 MW to 5,200 MW

ECAR to MAIN - 2,500 MW

MAIN to ECAR - 5,000 MW

ECAR to MPCC - 2 550 MW

MPCC to ECAR - 3,250 MW

ECAR to SERC (TVA) - 1,900 MW to 3,000 MW

SERC (TVA) to ECAR - 2,400 MW

ECAR to SERC (VACAR) - 3,400 MW

SERC(VACAR) to ECAR - 2,500 MW

MAAC from the Councils connected to MAAC - values ranging between 2,800 MW and 5,500 MW

Values from MAIN to other Reliability Councils ranging from 850 MW for the Southwest Power Pool to 5,000 MW, and from other areas into the MAIN system, 2,000 MW to 5,000 MW

MARCA to other Councils - 950 MW to 1,000 MW, except for 100 MW to WSCC

Other Councils to MARCA - 600 MW to 1,000 MW

New York Coordinating Council - 3,200 MW to 3,500 MW

Other Reliability Councils to NPCC - 2,300 MW to 2,500 MW

From SERC to other regions values ranging from 2,400 MW to 4,200 MW

From other Regions to SERC values ranging between 1,900 MW and 4,600 MW

From the Southwest Power Pool values between 2,000 MW and 3,900 MW

From other Regions to the Southwest Power Pool - 850 MW to 4,200 MW

From WSCC to MARCA - 100 MW

From MARCA to WSCC - 100 MW

ERCOT to other Regions - 0 MW

ANSI/IEEE Standard 100-1977 defines installed reserve as the reserve capability installed on a system.

Installed reserve requirement is the amount of capability installed on a system to meet a broad number of operating conditions such as carrying the load reliably and economically, protecting against load forecasting errors and equipment failures, providing adequate regulation of frequency in power flows on transmission lines (NAPSIC Operating Guide No. 10).

Intraregional interconnections between the electric utilities of ERCOT tend to reduce spinning reserve requirements.

An individual system does not have to cover the largest single hazard because the interconnection allows help from another utility. The intraconnections provide a more reliable system than an isolated one and, therefore, allows the reduction in percent reserves. The intraregional connections have allowed a reduction by each operating company in spinning reserve to the present level of approximately 6%.

Yes.

To do this in the intraregional system we note that presently ERCOT maintains a 15% installed reserve requirement on a planning basis. However, planning engineers of the area are concerned because the forced outage rates of large thermal units are increasing and because of this would prefer to see reserve margins above 25%. This reliability council, by relying on interconnections with the Southwest Power Pool, would be able to improve system reliability and to a degree offset the effect of increased forced outage rates on the system reliability. By relying upon its interconnections in emergencies, providing the interconnections are properly planned and properly installed, the power supply reliability will be improved with large interconnections. Improved reliability results in potential reduction in reserve margin. The Southwest Power Pool, by a statement in their planning criteria clearly recognizes that 3% reduction in reserves can be achieved with the demonstrated reliability studies. Within the PJM Pool (MAAC Reliability Council) a reliability index of one in ten is used to determine reserve margins. The PJM Pool also relies upon its interconnections to reduce reserve margin by 9% because of such interconnections.

The FERC Reports entitled, "Preliminary FPC Staff Report", dated April, 1977 and the "Technical Study for ERCOT Interconnection and Reliability Evaluation", dated March, 1978.

According to the Preliminary FPC Staff Report of April 1977, the composite ERCOT group would need a 20% reserve margin to meet a reserve criteria of one day in ten years and, when interconnected with the Southwest Power Pool, the total group would need a reserve margin of 16%. Thus, using that study for results, we see a 4% savings in installed reserves for the same reliability index. Since ERCOT is in a changing fuel situation, there are surplus capacities and, therefore, on a practical basis it might be 10 years before the full savings could be realized.

Spinning reserve is generating capacity or its equivalent connected to the system and ready to immediately carry or take load.

The spinning reserve requirement is that amount of capacity or its equivalent which, through experience in an operating area, must be available to maintain an adequate operating system.

Intraregional interconnections reduce the spinning reserve requirements of individual ERCOT utility systems to a common denominator of the area. The area requirement is defined for those companies reporting to two security centers, the North TIS and the South TIS. Each area has a spinning reserve requirement equal to the sum of the capability of the largest unit in operation plus 100 MW.

Spinning reserve can be reduced especially in a region that now must spin reserves for its largest hazard when that largest hazard exceeds the amount needed for load and frequency regulation. The reason for this is that the area's hazard can be further mitigated through the interconnections with other areas.

Regional systems with adequate interregional ties must first carry enough spinning reserve to satisfy normal system operations; that is, load and frequency control. This amount is approximately 3% of the load on the system. Consideration also must be given to the largest hazard in the area. Whereas at the present North TIS spins reserves for its largest hazard plus 100 MW and Southwest TIS does the same, with interregional connections the entire ERCOT area would not have to consider its largest two hazards but only give consideration to its largest single hazard.

This would amount to 2,600 MW in 1984 when Comanche Peak and South Texas nuclear plants are in service. By interconnecting outside of the area, this spinning reserve can be reduced to the largest single hazard, or approximately 3% of total load whichever is greater.

Approximately $4 million to $16 million per year savings beginning in 1984.

Opportunity sales, firm sales, maintenance energy and capacity, emergency energy and capacity, energy banking, capacity and energy sharing.

Same.

Economy exchanges are what has been called opportunity sales. These are exchanges which occur on an hour-to-hour basis when it is more economical to purchase power from a neighboring system than to generating it on your own system on a decremental/incremental basis.

Only on a limited basis. Interregional interconnections would enlarge the opportunity for exchanges because there would be greater opportunity to keep the larger, more economical units of the complete interconnected system fully loaded or above minimum loads.

Yes.

Load diversity is the ratio of the sum of individual maximum demands of various subdivisions of the system to the maximum demand of the whole system. Diversity exists instantaneously, hourly, weekly, seasonally and yearly. Diversity exists within the ERCOT system.

Load diversity is used to reduce the hourly demand on a system, thereby amount of capacity on an hourly basis needed to satisfy total load. Diversity also results in requiring less total installed capacity to meet maximum demands.

ERCOT as a group does not engage in economy dispatching and, therefore, does not take advantage of load diversity throughout the entire system. Presently, control area ties between the nine systems are controlled and energy between systems is periodically balanced. This results in each system dispatching to its own load and diversity is therefore not considered. Seasonal diversity, if it exists, can be taken advantage of by reducing installed generation in the two areas that have seasonal diversity. Hourly diversity may be a benefit through central economic dispatching on an hour-by-hour basis. The benefits of yearly diversity can be acquired by long-range generation planning between areas. ERCOT utilities do not take advantage of load diversity.

Yes.

Utilities in neighboring areas may study their seasonal and yearly load patterns and develop the magnitude of seasonal and yearly diversity and, by contract, can develop capacity exchanges.

In general I am familiar with the TVA/SWPP load diversity exchange.

Through my participation in the industry and through technical and industry publications and through the 1970 National Power Survey.

This is an example of transactions permitted through interregional interconnections. Another example that I am familiar with is the exchange between Allegheny Power Systems and the Virginia Electric Power Company (VEPCO), for seasonal diversity exchange of 400 MW. Another diversity exchange that I am familiar with or have heard about is between Manitoba Hydro and Northern States Power which, I believe, is for 1,000 MW. There is also seasonal diversity exchange between the Pacific Northwest and the Pacific Southwest in an order of magnitude of 2,000 MW. This is an example of types of transactions permitted through interregional interconnections. The TVA Southwest Power Pool load diversity exchange was initially projected to grow to approximately 5,000 MW. However, later studies reduced that to 2,500 MW.

There is probably very little seasonal diversity between ERCOT and other regions. Between ERCOT and the Southwest Power Pool there is very little seasonal diversity. The diversity between TVA and Southwest Power Pool could have been shared by ERCOT but with similarities in load between the Southwest Power Pool and ERCOT and because the diversity is already under contract, it is doubtful that ERCOT would be able to share in this.

Benefits of load diversity transactions are on a sliding scale somewhat in proportion to the magnitude.

Central economic dispatch is a means by which the generation on an hour-to-hour basis is controlled in such a manner as to most economically satisfy the system load requirements.

ERCOT utilities on an individual basis are dispatching their generation to most economically satisfy their own hour-by-hour system loads. However, as a group, ERCOT utilities do not participate in area economic dispatch, which would include the advantages of diversities between the individual systems and within the whole area.

Yes.

Entities most likely to participate in dispatch across an interregional interconnection with ERCOT would be those utilities on the edge of the region, perhaps the Central and Southwest Holding Company Utilities (Central Light and Power, West Texas Utilities, Public Service of Oklahoma and Southwestern Electric Power Company); Houston Power & Light with GSU; COA or LCRA; Texas Utilities with OG&E, etc.

No.

The ability to generate and deliver power to serve system loads in a dependable manner.

With the interregional interconnections reliability is improved. On the other hand, should the systems decide to maintain the same degree of reliability as without the interconnections, installed capacity can be reduced.

Interregional connections between ERCOT and Southwest Power Pool would increase reliability.

Because of the fact that during an emergency when capacity is lost to the system, the ties permit the exchange of capacity from the other region.

To coordinate the use of the intraregional transmission system, power flow over the transmission lines would need to be measured and telemetered to a central dispatch center which, in turn, would control the dispatch of area generating equipment. Such type equipment is commonly known as tie-line load control equipment.

The same type of equipment would be required for interregional interconnections.

Tie line frequency load control is used to monitor all tie lines which interconnect one control area with other control areas. Information received from monitoring equipment on these interconnections is totalized for the area and relayed to the economic dispatch computer which, in turn, dispatches area generation to most economically meet the load demands of the system taking into account proper exchange from the tie lines.

Each of the tie lines which would be established as interconnections between ERCOT and Southwest Power Pool, presently described as approximately five in number, would need to be monitored and through communications channels telemetered to the proper area control center within ERCOT and Southwest Power Pool.

Tie line frequency bias control not only takes into account the flow of power over interties, but also provides a method of representing the responsibility of the control area with regard to system frequency variations.

Yes.

The information over these five tie lines would be telemetered to the proper control area within ERCOT and used in the same manner as previously described.

The electrical power output of a turbine generator set is determined by the amount of steam entering the turbine. In order to control the electrical output, the amount of steam entering the turbine must be controlled. The process for doing this is by utilizing a governor to manipulate the inlet steam valve. The governor is responsive to speed change, which translates into frequency change of the turbine generator set. Governor action is a term used to describe the responsiveness of the governor to speed change.

Yes.

Yes. Governor action would be necessary with any type of interconnections. Underfrequency relays are system devices which are used to drop load should an underfrequency condition on the system exist for a period of time.

Yes. Momentary flows are those flows which exist for very short periods of time until system regulating changes can take effect.

Yes.

A transmission system is designed to withstand continuous flow of electricity. Inherently the physical properties of the transmission system are such that the ratings for power flow are increased as the time of their existence decreases. Transmission systems also have emergency ratings which are above the continuous rating which allow for an increased flow of electricity during an emergency that might exist for an hour or so. Momentary flows on EHV systems which exist only for seconds do not reach a magnitude which is damaging to a transmission system that has sufficient continuous capability. Momentary flows between ERCOT and Southwest Power Pool would not be damaging to the ERCOT system.

Inertial inrush is a term used to describe the conversion of stored energy contained in the rotating mass of the turbine generator set into electrical energy on the power system. Such a conversion is created by a sudden disturbance on the electrical system such as a power system fault which is an extreme disturbance or the tripping of a turbine generating unit off-line which is of less magnitude.

Yes.

Inertial inrush exists within the ERCOT system and has no adverse effect. If ERCOT had interregional interconnection, the inrush would have a supportive effect in that it would assist in maintaining a constant frequency on the system.

Power pooling is a term used to describe the pooling of generating systems between two or more entities to achieve operational and/or planning economic benefits. ERCOT takes advantage of power pooling only to the extent of coordinating planning and operations. The area is taking advantage of the economy of operational power pooling by exchanging economy energy, on a limited basis. Yes.

No.

Presently, there exists 900 MW of transmission capacity between North TIS and South TIS. There are two functions for this capacity; one function is for emergency assistance between North TIS and South TIS and the other function is to exchange power from one area to another. Assuming that the 1,200 MW (largest machine hazard) would require transmission capacity, which it certainly will, and there is a desire to exchange 1,000 MW of power continuously between North TIS and South TIS, this then would require the addition of two 345 kV lines.

With the assistance that interregional ties would give, part of the capacity reserved for emergency conditions would not be needed and therefore, to that extent, less intraregional capability would be required. Of course, if the interregional connections are longer in total length than the intraregional additions, from an overall point of view it may turn out that no transmission construction would be saved.

The reason for this is that during the condition of loss of a south Texas nuclear unit interties to the Southwest Power Pool would assist the system and thus give additional parallel assistance to that of the North TIS area. For a loss of the Comanche Peak unit, in addition to assistance being available from South TIS, with interregional connections, assistance would be available also from other sources and thus there would be less impact upon the ERCOT system.

Yes, almost always.

A good example is the Pacific Northwest-Southwest Intertie. This system was originally planned on the basis of cost benefit ratio of 2 to 1, whereas in actuality, additional uses have been made beyond those originally planned for and the cost benefit ratio for the first ten years of operation has been approximately 10 to 1. The 500 kV, 600 mile line from the Four Corners area into California originally was planned on the basis of delivering power from the Four Corners generating unit to Southern California; whereas, today it is part of the entire integrated WSCC system which carries economy exchange power from Colorado, Utah and Idaho to Southern California as well as economy exchange power from the Arizona area into Southern California. In addition, during the Northwest draught, because of the intertie the entire western United States was able to assist in hydro power shortages in the northwest. During extreme draught conditions in California, Pacific Gas & Electric Company (normally a 40% hydro operating company) was able to import power from all of the western states to prevent power shortages over the entire Western Grid. During the oil embargo of 1974, power shortages for the entire east were prevented because of the ability to import generation from the midwest and south over interregional ties. During the coal strike in the winter of 1977/78, the eastern utilities who were largely burning coal, were able to import enough power from areas to the west to prevent power shortages over their interregional ties.

Requires FERC report on electric power disturbances. In response to FPC Order No. 331-1.

Unplanned emergency conditions created by weather, fuel shortages, regulatory shutdown, shortages of lignite mining ability, railroad strikes when importing western coal, heat storms hurricane situations, and sudden widespread problems, etc. would be provided for by interregional interconnections.

Without interregional interconnections, ERCOT would have to increase its force majeure coal reserve to be able to withstand longer interruptions of western coal supply; it would have to increase installed reserve to withstand such situations where practical, and in the ultimate, probably they would see power shortages and curtailment of loads under the circumstances previously described.

I was a member of the Pacific Northwest-Southwest Intertie System planning committee from its inception until the Intertie was operable. During that time, we developed the power flow and system stability programs large enough to study the entire interconnected WSCC system.

As initially designed and planned for, capacity of this was 3300 MW. In 1976, the intertie was uprated to 3800 MW and at present, it is contemplated that the intertie will be uprated to 4350 MW. The Pacific Northwest-Southwest Intertie was originally established to exchange surplus power and energy from the Northwest to the Southwest and to interchange seasonal diversities.

Additional benefits have been realized through seasonal banking of energy, through economy purchases, through increased marketing area power exchanges. The result of this is the cost benefit ratio for the first ten years of operation is five times the cost benefit ratio of the original feasibility study.

Intangible benefits created when operating people are able to establish a better coordination of maintenance outages of units in a local area, through preventing power shortages during civil strife, through sudden severe weather storms, through unplanned sabotage items; such items are additional benefits, normally not contemplated but which result from interregional ties.

The changing fuel situation and the desire to take maximum economical advantage of large lignite and western coal-fired power plants and large nuclear power plants rather than the continuation of generation fired by oil and gas.

Larger units create larger system hazards, increase the outage rates of generating units, present problems of exactly forecasting the inservice date of large generating units which require eight to twelve years of lead time, problems created by safety requirements as they may change during the operating life of nuclear units.

Existing are seven lignite units ranging between 575 and 750 MW and existing are 17 oil/gas units ranging between 500 and 775 MW. According to the April 1979 Report R-362, ERCOT is planning the following additions:

<u>Prior to 1979</u>

Big Brown #1 & 2 - 775 MW

Martin Lake #1 & #2 - 750 MW

Monticello #1 & #2 - 575 MW

Monticello #3 - 750 MW

<u>1979</u>

Martin Lake #3 - 750 MW

Sycamore #1 - 550 MW

Coleto Creek #1 - 550 MW

<u>1980</u>

Sycamore #2 - 550 MW

Parish #7 - 570 MW

<u>1981</u>

Comanche Peak #1 - 1150 MW

Sandow #1 - 575 MW

<u>1982</u>

South Texas #1 - 1250 MW

Gibbons Creek # - 400 MW

Parish #8 - 540 MW

1983

Comanche Peak #2 - 1150 MW

South Texas #2 - 1250 MW

1984

Twin Oak #1 - 750 MW

Forest Grove #1 - 750 MW

1985

Martin Lake #4 - 750 MW

Allen Creek #1 - 1130 MW

Undetermined - 750 MW

Yes

Larger size units are less reliable because in many cases they are new types of design with different technology than in the past and in all cases, the units do not use clean natural gas fuel but rather are nuclear, sub-bituminous western coal or lignite coal plants. With large coal-fired plants, there is considerably more equipment involved in fuel handling and in the burning of the fuel. All of this results in a less reliable power source. In the case of nuclear units, while the reliability is good, the units are subject to changing safety regulations and period of limited generation ability. The nuclear units also require longer maintenance period annually for fuel loading and unloading than oil/gas units.

There should be enough spinning reserve on the system to respond and adjust to the operating hazard of losing a complete generating unit without going into load shedding.

Yes.

Because large units are more economical and therefore, on a economic dispatch basis would be loaded up. Also large units have more difficulty from an operating control point of view in responding to changing load conditions and smaller units are usually used for load swinging. Also, the larger generating units have larger turbine shells and fluctuations in loading tend to cause thermal stresses which decrease the life of these turbine shells. Also, large generating units tend to have the large, long turbine rotor blades and changing loading or changing system conditions must be controled very carefully to preserve these blades. Also larger units have larger turbine-rotor spindles and changing loading conditions lend to stress the complete spindle.

Yes.

Spinning reserve will be carried by small units dispersed over a large geographic area and connected by the transmission system. Therefore, the area will become more and more dependent upon its transmission system.

Yes.

Referring to the eighth annual NERC review, by 1987, the area will have 20% of its generation from nuclear sources and 47% from coal sources.

The uranium will come from outside the state of Texas and the sub-bituminous and western coal will also come from outside the state of Texas.

The cost of transportation will be a significant item in the delivery of western and sub-bituminous coal to the state. The availability of these fuel sources will be dependent upon the transportation system and upon the availability of coal at the mine.

The state will be more exposed to fuel shortages than it has known in its history, and the reliability of power sources widely dispersed through out the entire southwest will be more important, and therefore, greater emphasis will be placed upon interregional interties.

They will be subject to regulatory controls that are imposed on the rail and pipeline industry, and upon the regulatory controls imposed on the nuclear industry. In the case of transportation and pipeline industry, they will be more susceptible to the regulation of the Interstate Commerce Commission. In the case of the nuclear, they will be more subject to the regulation of the Nuclear Regulatory Commission. State and local regulation will also become an increasing important factor, due to the increase in railroad traffic.

ERCOT will need to more carefully plan its fuel supply and in addition, will increasing rely on interconnections in times of supply shortages and in times of catastrophic conditions such as have already been experienced in other parts of the country.

Blank.

As fuel costs go up there is more and more incentive to realize the economies of improved efficiency of operation through use of inter and intra regional ties.

Yes.

Texas has been blessed with an abundant supply of oil and natural gas so that up until now it has been relatively easy for the operating companies, particularly in central and southeastern Texas, to locate the power plants near the fuel sources which are, in turn, near the load centers of the state.

The trend is now to move the generation plants further away from the load centers.

Lignite as a fuel is a very perishable commodity and is very difficult to transport over any haulage system, therefore, the lignite-fired generation is being located at the mine as mine-mouth plants. The burning of sub-bituminous and western coal will also have an impact in that the people pressure will be to keep these plants away from the load centers.

This will mean extra emphasis on the need for both inter and intra regional interconnections. The age old industry argument concerning the economics of transporting electricity versus transporting fuel will again arise and conceivably power plants closer to the western coal sources with transmission lines into the load centers will be more economical than shipping the coal all the way to the Texas load centers for use. The region will learn to rely more on its transmission system than it has in the past.

Major experience in utility industry throughout ERCOT has been with oil and gas fired equipment in which they have pioneered the development of the large sizes which exist. With the changing fuel situation to lignite, sub-bituminous, western coal and uranium, these same utilities are faced with a brand new technology. For instance, prior to 1979, there were only seven lignite units in the entire state. Big Brown, the first plant that went into service, has been on line for only a few years. Coleto Creek #1 will be the first unit on sub-bituminous coal in the state and it is scheduled to go into service in 1979. Sycamore #1, a coal plant rather than sub-bituminous coal, is scheduled to go in service in 1979, also the first of a type, as far as coal type is concerned. ERCOT has relatively little experience in coal-fired power plants. Comanche Peak, scheduled for 1981-83 operation, will be the first nuclear plant in the state. By the end of 1985, ERCOT will have developed over 18,000 MW of coal and nuclear fired capacity, 12,000 of which is scheduled to be placed in service between 1979 and 1985.

Lack of experience with these new types of fuel, together with the experience of other parts of the country can be translated into the need for increased reserve over what the ERCOT system has been accustomed to, and it will lead to increased use of the EHV transmission system during emergency conditions, for economy exchanges and for the coordination of maintenance on an ever-widening horizon. The transmission system will undoubtedly be further developed and undoubtedly the area control centers will change into a more amalgamated operation.

The result of this will be a ever pressing need for more interregional interconnections.

I would favor an adequate, properly designed interconnection.

I would favor such an interconnection because of the overwhelming benefit to the area when interconnected.

Either type would be satisfactory.

The interconnection should be an adequately planned one to perform properly between the two areas, either AC or DC would work satisfactorily from a technical point of view. The industry has over ten years of experience in the United States with DC and throughout the world, perhaps 15 years of experience. This experience has been good experience. The industry has had many years of experience in developing large AC interties which work equally well. The DC ties would pretty much duplicate the isolated operation now experienced by ERCOT and would deny the benefits attainable during transient and dynamic conditions on the AC. The DC probably will be more expensive than the AC for the same transfer capability between regions but will have only limited emergency transfer capability.

The FERC studies demonstrated the five points of interconnection. From the size of the ERCOT system, I would believe that technically acceptable performance could be achieved with three to four thousand MW of emergency transfer capability within the interconnections providing the intra-interconnections are sufficient to maintain system integrity. These, of course, are only experienced judgment numbers and before any system engineer would be satisfied, he would require the technical studies to verify the statements.

From my experience, I believe it would take approximately one to two years of study and planning work to determine how to effect such an interconnection. Beyond that, the actual facilities could probably be built within five years. Overall, that would probably amount to five or six years total elapsed time.

The study work would probably be on the order of $250,000 to a half-million dollars. 345 kV lines cost approximately $150,000 a mile, (1978 dollars) and 500 kV lines cost approximately $250,000 a mile (1978 dollars). To project to other years, I would use 8% escalation. A DC converter station will cost approximately $80 to $100 per terminal; two terminals would be needed, therefore, $160 to $200.