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Analysis of Power Wheeling Services

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ENERGY DIVISION

ANALYSIS OF POWER WHEELING SERVICES

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Executive Summary

ES.1 Purpose of Study

The purpose of this study is to examine existing wheeling arrangements to determine the terms of the agreements, to analyze the terms relative to regulatory goals, and finally, to suggest ways in which the arrangements can be modified to lead to outcomes more closely in line with the goals. The regulatory goals that are considered are: Does the arrangement meet the revenue requirement of the wheeling firm? Is efficient use promoted? Are the costs fairly apportioned? And, is the arrangement practical and feasible to implement?

ES.2 Definition of Wheeling

There are a number of definitions of power wheeling services in common usage. For this study, wheeling is limited to a narrow definition to differentiate it from other types of power transactions in which utilities engage. Wheeling is defined as the simultaneous transfer of electrical power over transmission facilities owned by a utility that does not own the transferred electricity. The phrase "simultaneous transfer" limits wheeling to transfers in which the wheeling utility receives the power on its lines at the same time as it delivers power to the purchasing utility, or to another wheeling utility.

Typically, a wheeling transaction is recorded as a formal contract between the utilities involved in the transaction. A contract for one type of wheeling service will be referred to as a "wheeling arrangement" in this document. The contract may be a separate agreement, but often is part of a larger agreement which may contain power sales arrangements or arrangements for different types of wheeling services. The arrangement may be between two utilities (a bilateral arrangement), or among a number of utilities (a multilateral arrangement).

The arrangements generally specify particular terms and conditions under which the wheeling service will take place. These terms and conditions can be categorized into five areas:

1. type of transmission service provided;

2. compensation methods and rate forms;

3. specific service requirements;

4. notice and response requirements; and,

5. other miscellaneous requirements.

Because the arrangements involve sales between utilities, most arrangements involving investor-owned utilities are regulated by the Federal Energy Regulatory Commission.

ES.3 Importance of Wheeling Transactions

Currently, many utilities have a surplus or otherwise non-optimal stock of generating equipment. This problem has been mainly caused by the substantial rise in oil prices in the last decade and the general rise in all energy prices, due partly to the increase in oil prices. Because of these changes, some existing units have become uneconomical to operate relative to other units. Increased prices for electricity have also reduced or eliminated growth in electricity demands. One response to these changes has been a strong effort by utilities to achieve economies through bulk power transfers. As a result, the growth of inter-utility power sales has been strong throughout the last decade. Because wheeling services are often needed for power sales to occur, the growth in wheeling service has also been very strong.

Because power transmission is characterized by large economies of scale, it is a classic example of a natural monopoly. Such monopolies enjoy unusual market power, and regulation can usually lead to greater efficiency and welfare gains for society. To achieve these gains, regulation must achieve certain goals. These goals can be summarized into four areas: (1) meeting revenue requirements; (2) promoting efficient use of capital stocks; (3) fair cost apportionment among parties to the wheeling agreement; and (4) feasibility and practicality. If these goals are met, welfare gains can occur, but failure to do so could leave power users worse off than before the transfers.

ES.4 Examples of Wheeling Transactions

There are a number of transactions types which are classified as wheeling for this study. These are illustrated in the following figures. The blocks in the figures represent utility service areas. Solid lines connecting two blocks indicate electrical interconnections between utilities.

ES.4.1 Three-Party Wheeling

Figure ES.1 shows a simple three-party wheeling arrangement. Utility System A agrees to sell power to System C, but A is not directly interconnected to C. However, A and C are connected through System B, so the sale can be carried out by wheeling power through System B. Utility System B thus serves as the wheeling system in this operation.

ES.4.2 Two-Party Wheeling

An example of a wheeling operation involving only two parties is depicted in Fig. ES.2. A generator owned by utility B is physcially located in utility A's service area and is connected to System B only through lines owned by A. Therefore, utility B both generates and sells the power for final use, but utility A transfers the power from the generator to utility B's lines. Thus utility A is the wheeling utility for this transaction. This can also occur with jointly-owned generating facilities.

ES.4.3 Wheeling To a Utility with No Internal Generation

Utility A, shown in Fig. ES.3, owns no generation facilities and normally purchases power from utilities B and C. If utility A now wishes to purchase power from utility D, it must obtain assistance in transferring the power, because it is not directly connected. If utility C agrees to transfer the power from D to A, it serves as the wheeling utility.

ES.4.4 Multi-Party Wheeling

Fig. ES.4 indicates how a wheeling transfer can envolve more than one wheeling utility. In this case, a power transfer is planned between systems A and E. Because systems A and E are connected

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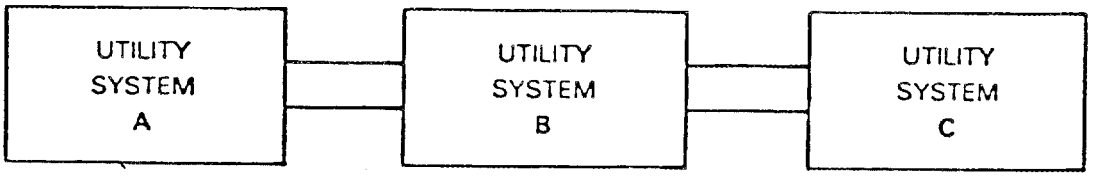

Fig. ES.1. Three-party Wheeling

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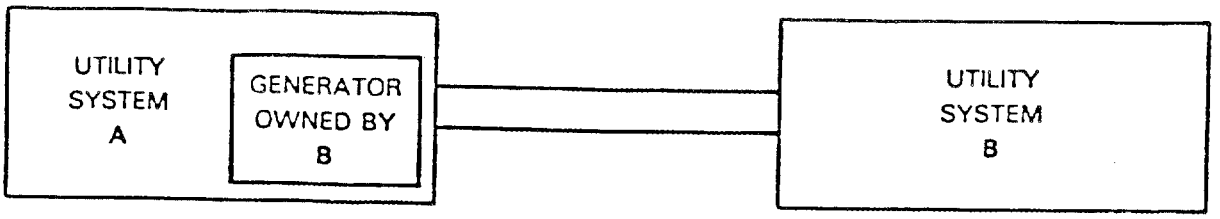

Fig. ES.2. Two-party Wheeling

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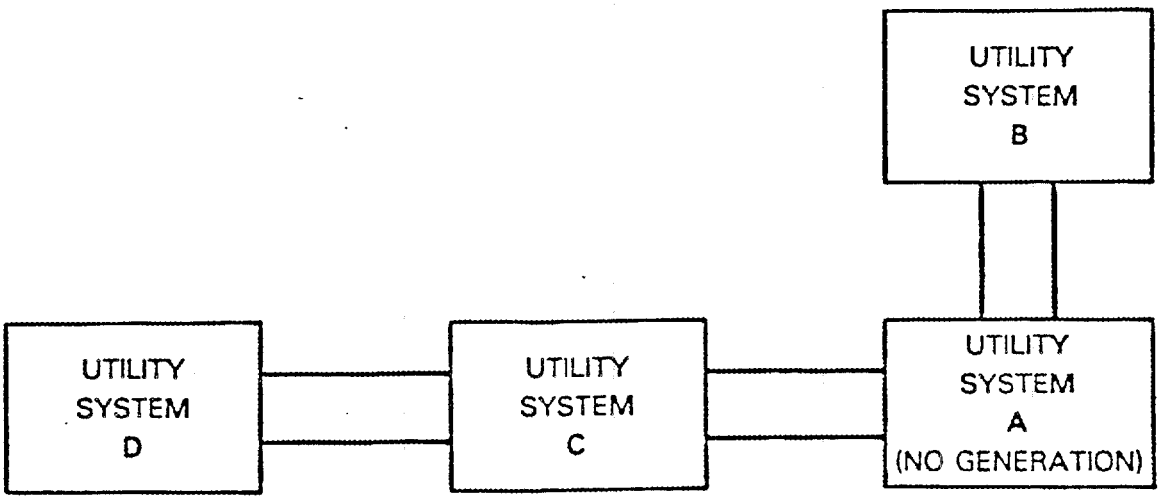

Fig. ES.3. Wheeling to a Utility with no Internal Generation

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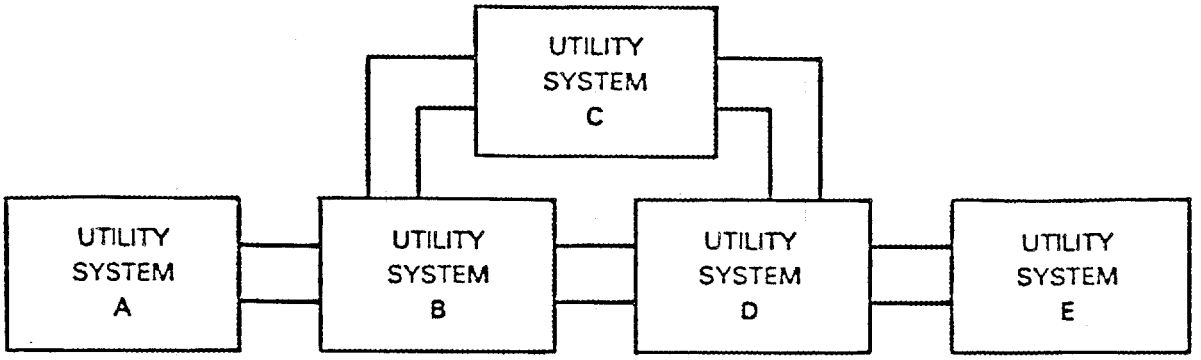

Fig. ES.4. Multi-Party Wheeling

through systems B, C, and D, the transfer could take place through one or more of these three systems.

ES.5 Examples of Non-Wheeling Power Transfers

ES.5.1 Two-Party Transfer

Figure ES.5 shows a simple two-party power transfer, in which utility A sells power to utility B. In this case, utility A generates the power, and utility B sells it to end-use customers. By the definition of wheeling used throughut this report, this does not constitute a wheeling transfer, because there is no utility involved in the transfer other than the one generating the power and the one selling it.

ES.5.2 Combination of Wheeling and Non-Wheeling Transfers

Fig. ES.6, shows a power transfer that combines wheeling with a conventional power sale. Utility A delivers 200 MW to Utility C, which was sold by A to C. Thus, there are two transactions taking place: 1) a 100 MW wheeling transfer between A and C, with B acting as the wheeling utility; and 2) a conventional sale of 100 MW from A to B.

ES.6 Technical Effects of Wheeling

There are two types of technical effects due to a wheeling operation that impact the wheeling utility: (1) altered delivery system loading, and (2) altered generating unit commitment or economic dispatch. These effects will result in changes in overall production costs for the wheeling utility.

ES.6.1 Altered Delivery System Loading

A major effect that a utility will encounter during wheeling is a change in the loading of its power delivery system. This may affect any of its delivery functions or any part of its delivery system. Some parts of the system may experience increased loading, while on other parts the loading may be decreased. Where loading is increased, there will be an increase in delivery system losses. The costs resulting from these additional losses will be the cost of increased generation or imports to replace the power lost. On the contrary, if loading is decreased by the wheeling

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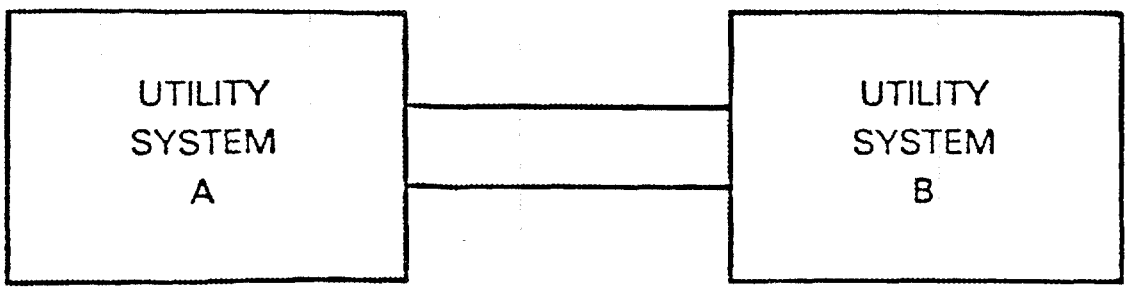

Fig. ES.5. Conventional Two-Party Transfer

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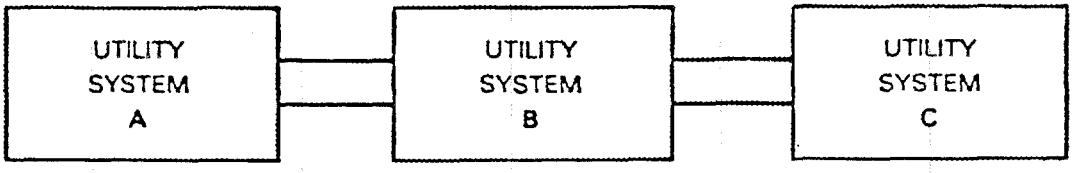

Fig. ES.6. Three-party transfers

operations, line losses will decrease, allowing a comparable reduction in generation or power imports.

Both real and reactive power loading can be affected by a wheeling transaction. Real power flows are affected wherever real power is transferred across the wheeling system. Reactive power loading can also change, not only because of conditions on the wheeling system, but also because of conditions on the generating system, or on the customer's system. Provisions may be contained in the wheeling agreement which require that the wheeling utility be compensated if changes in reactive power loadings arise as a result of conditions in these latter two systems.

Another potential impact of altered delivery system loading is a decrease in the life of current-carrying components (transformers, conductors, generators, etc.). However, because component loadings will usually remain within normal ratings during wheeling, this effect will be small and the complex calculations required to determine loss of life are probably not justified.

Losses on the wheeling system can be recovered in two ways. The first is for the wheeling system to simply generate more power to make up for the increased losses. The second is for the wheeling system to subtract the power losses from the power it receives from the selling system. In this case the wheeling system would deliver less power to the receiving system than it received from the seller.

ES.6.2 Altered Generation Unit Commitment or Economic Dispatch

The optimal generating unit commitment (also referred to as economic dispatch) of the operating system may also be altered by some wheeling operations. When power flows in a system are changed, optimal commitment may be altered. The changes may either improve or degrade the operating economics of the system. The costs or benefits due to these changes arise from the varying operating costs between generators (fuel costs and unit efficiency) and also from the line losses along various delivery paths. These costs can be quantified using the wheeling utility's production costing methods.

There are several instances in which a wheeling operation will affect generation on the wheeling system:

- When power flows on a system are sufficiently altered by wheeling that a new distribution of power flows is necesary for economic reasons

- When increased power losses caused by wheeling are compensated for by increasing generation on the wheeling system.

- When wheeling causes certain lines to be loaded to their limits, making it necessary to redistribute the power flows on the wheeling system.

- When wheeling is to be accomplished by displacement.

ES.6.3 Changes in Production Costs Due to Wheeling Transactions

Production costs are the variable operation and maintenance costs incurred by a utility to produce a given quantity of electric power. Relatively fixed costs, such as depreciation and routine structural maintenance need not be considered. Every utility has its own techniques for determining production costs, though these techniques differ in the amount of detail used. Some use detailed production analysis computer programs, while others compute costs by applying relatively simple formulas. The factors dictating production costs are the same for all utilities, i.e., availability of generating resources, generation efficiency, fuel costs, and line losses. Change in any of these components result in production cost differences. The costs of a specific wheeling operation must be evaluated using the wheeling utility's production cost models and formulas to compare the cost of normal operation (without wheeling) with the costs during the wheeling operation.

For some wheeling transactions, it may be necessary to increase the level of spinning reserves on the wheeling system to account for the potential loss of the power imported for wheeling. If the wheeling import is unexpectedly lost, the utility to which the power is being wheeled will still be present as a load on the wheeling system. While most wheeling agreements would allow the wheeling utility to immediately halt exports to the receiving system, the necessary control actions to do so require a finite amount of time, and additional spinning reserves may be necessary to maintain the wheeling system's stability during that time. The cost of any needed additional reserves is an additional cost of the transaction.

In contrast to the need for additional reserves, the amount of unloadable generation present on the wheeling system may need to be increased during the wheeling operation. Unloadable generation is the amount of generation and imports which could be quickly removed from a system without resorting to emergency shutdown of a generating unit. If the export of wheeling power is suddenly stopped, there will be an excess of power entering the wheeling system, so the unloadable generation must be sufficient to compensate for such a loss. Again, the level of unloadable generation present on a system will need to be increased only if the amount of power exported for wheeling affects the formula used for determining unloadable generation. For example, if the wheeling export becomes the largest system "load," then unloadable generation would certainly have to be increased.

ES.6.4 Effect on System Stability

The altered loading of the wheeling system may have other adverse effects on the transient or dynamic stability of the system. If this occurs, steps must be taken to restore the system to a stable condition if the wheeling operation is to take place. Changes should be made to generator or line loadings, but if available changes are not sufficient, additional facilities will be required for the wheeling operation to take place.

ES.7 Feasibility of a Wheeling Operation

The projected effects of a proposed wheeling operation must be analyzed to evaluate the feasibility of the operation before it is carried out. Whether or not a wheeling transaction is feasible may be answered by simulation, if during the transaction an adequate level of reliability is maintained on the systems providing the wheeling service, the transaction is considered feasible.

There are several ways to evaluate the reliability of a system, but the majority of U.S. utilities presently use deterministic criteria in assessing transmission system reliability. A first contingency incremental transfer capability is defined as: "The amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions:

1. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The bulk power system is capable of absorbing the dynamic power swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer.

3. After the dynamic power swings following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer, but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits."

For a utility using this criteria, the system must meet the three conditions during all operations, including wheeling. Some systems use more stringent criteria, such as second contingency incremental transfer capability, in which the system must be able to withstand any two simultaneous contingencies. Whatever criteria are used in normal operations also apply to wheeling operations.

If a system does not meet the necessary reliability criteria during a wheeling operation, changes should be made in system generator and line loadings in an attempt to meet the criteria. If these changes are not sufficient, then additional facilities will be required for the wheeling operation.

ES.8 Specific Costs Associated with Wheeling

Seven major types of economic cost may be created by wheeling transactions. These costs are:

1. The cost of producing power to replace line losses associated with wheeling;

2. Incremental transmission operating and maintenance costs;

3. Incremental real depreciation of transmission facilities;

4. Incremental capacity costs if the wheeling utility must add transmission capacity to carry out wheeling transactions;

5. A reduction in the quality of service to the wheeling utility's retail customers and firm wholesale customers if the wheeling transactions reduce the reliability of the transmission system or increase costs to maintain reliability at a given level;

6. Opportunity costs which result from the fact that other entities are unable to complete an econmically efficient power interchange transaction because the transmission capacity of the intervening utility that must wheel the power is fully loaded; and,

7. Changes in utility operations, such as, unit commitment, economic dispatch, reserves, and unloaded generation.

The first type of economic cost is incurred by the utility that furnishes the wheeling losses, although payment for such costs is typically made by the utility purchasing the wheeling services. The second, third, and fourth types of economic cost may be incurred by the utility providing wheeling services. The fifth type may be incurred by the utility's firm customers whose electric service is interrupted more frequently as a result of wheeling transactions. The sixth type of economic cost reflects the higher cost of service incurred by other entities that are unable to complete cost-effective power transactions requiring wheeling services with the wheeling utility. The final cost can be incurred by any utility interconnected with the wheeling utility but usually are incurred primarily by the wheeling utility.

All major wheeling costs are defined in terms of marginal costs. Embedded costs associated with a utility's existing transmission system (e.g., taxes and insurance on gross transmission plant less accumulated depreciation reserve). Specifically, embedded costs of existing plant are irrelevant from either a planning or operating viewpoint and are not included. When a utility can meet the demand for wheeling services with its existing transmission system, the utility incurs no additional embedded costs by wheeling but may incur some of the marginal costs described above. On the other hand, if the utility cannot reliably meet the demand for wheeling services with its existing transmission system, the utility is faced with the decision of whether to add transmission capacity so that established reliability criteria can be met.

ES.9 Description and Classification of Wheeling Arrangements

There are over 1,000 wheeling arrangements on file at various agencies of government in the United States. These arrangements fall into one of two categories, according to method of compensation: tariffs and rate schedules. Tariffs are arrangements which do not specify particular participants but can be generally applied to general classes of wheeling customers. Rate schedules, on the other hand, are between specified participants. The arrangements usually are based on a number of characteristics:

1. type of transmission service;

2. compensation methods and rate forms;

3. specific requirements for service;

4. notice and response requirements; and,

5. other miscellaneous requirements.

Most of the arrangements are filed at one or more of several federal and state agencies. The largest group are those filed at the Federal Energy Regulatory Commission (FERC). These include most of the arrangements in which investor-owned utilities provide the wheeling services. The federal marketing agencies, such as the Alaska Power Administration, Bonneville Power Administration, Southeastern Power Administration, and the Western Area Power Administration, also have large numbers of wheeling arrangements on file, some of which overlap those on file at FERC. Some arrangements in which investor owned-utilities provide services to the marketing agencies are on file at both the agency and at FERC. The Tennessee Valley Authority (a federal agency) participates in one wheeling arrangement. The New York Power Authority (a New York State agency) participates in a number of wheeling arrangements within New York. Finally, the Texas Public Utility Commission has regulatory authority over wheeling arrangements among Texas utilities which are not interconnected outside the state. Some arrangements are filed with this Commission.

ES.9.1 FERC Wheeling Arrangements

The wheeling arrangements filed at FERC were carefully examined. FERC had 768 arrangements that satisfied the definition of wheeling used in this document.

Rate schedules (arrangments between specific parties) comprised 98 percent of the FERC arrangments, while tariffs (arrangement usually open to general customer classes) comprised the remainder. The arrangements can be broken down into firm and nonfirm catagories, with the distinction that a firm service agreement commits the wheeling utility to deliver power. Eighty percent of the arrangments were firm. The compensation methods used in the arrangements were almost balanced between specific rates (for example, dollars per kWh) and multi-part formulas.

Few arrangments had restrictions on the specific lines which were to be used, on delivery voltages, or on what the buying utility could do with the power. Similarly, most arrangements did not specify specific notice requirements for initial service startup or the response by the wheeling utility to the startup request. However, many (44 percent) specified a period for notification before permanent termination.

ES.9.2 Non-FERC Wheeling Arrangements

The wheeling arrangements at other agencies were also reviewed. Rather than a complete survey, however, a sample containing approximately 50 percent of the wheeling arrangements were examined. Eighty-three percent of the arrangements were wheeling with separate compensation for the wheeling service. A small but significant portion of the arrangements were tariffs.

The terms and conditions of the wheeling arrangments were markedly similar to those of the FERC arrangements. Firm arrangements comprised 81 percent for the FERC arrangements and multi-part rate formulas were used in 21 percent.

Few arrangements had limitations on the particular lines that could be used, or the delivery voltage. A substantial number though, had limitations as to whom the power could be sold. The only notice requirement present in a significant number of arrangements was notice for permanent termination.

ES.9.3 Classification System

The wheeling arrangements examined can be classified by two major characteristics:

1. The right of the wheeling utility to interrupt or curtail the wheeling service, and

2. The method used to compensate the wheeling utility.

The right of curtailment separates the arrangements into what is usually referred to as firm and nonfirm arrangements. The compensation method divides the arrangements into four basic types:

1. Specific rates (compensation is based on a per time unit of power quantity unit transmitted)

2. Multipart formulas (compensation is based on a formula and may vary from one point in time to another)

3. Split savings (gains from the wheeling transaction are shared by the participants), and

4. Banking or reciprocal arrangements (payment is made in-kind).

The specific rate compensation method is the only case where an actual rate is determined in advance. It can be further subdivided dependent on the units upon which the rate is based. These categories are shown in Figure ES.7.

Due to the necessity of consulting secondary sources to determine the appropriate classification of the wheeling arrangements (some important information is not included in some of the wheeling arrangements), only a sample of wheeling arrangements was classified. Two hundred FERC wheeling arrangements and 176 non-FERC wheeling arrangements were selected for classification. Because of the complexity associated with multi-part rate formulae and the possibility of overlap with other rate forms at certain times, they were excluded from the classification. The number of FERC wheeling arrangements falling into the classification

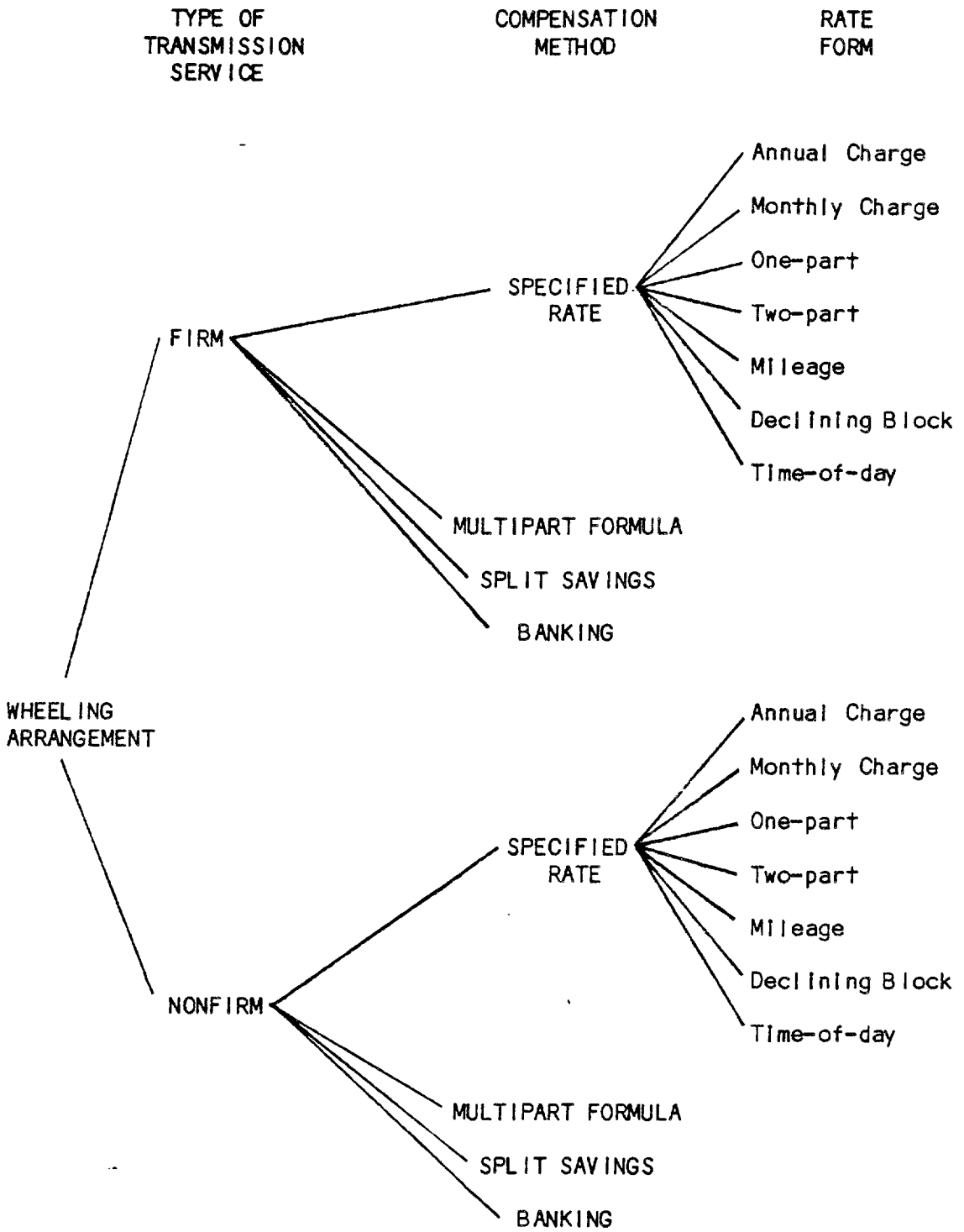

Fig. ES.7. Classification categories

categories is shown in Table ES.1 and the number for non-FERC wheeling arrangements is shown in Table ES.2.

ES.10 Detailed Examination of Wheeling Arrangements

In order to obtain additional information on the existing wheeling arrangements, a small sample of the wheeling arrangements identified in the previous section was selected for detailed examination and evaluation relative to terms and conditions and with regard to the goals of regulation. The arrangements were not chosen randomly, but rather because of some distinguishing characteristics. A total of 52 arrangements were examined.

ES.10.1 Type of Transmission Service Available

The types of transmission services offered in the arrangements fell into firm and nonfirm enterprises. Firm transmission service refers to service which can usually only be interrupted for:

1. specific kinds of emergency siguations created by factors not under the control of the utility, for example, weather-related failures;

2. possible impairment of the operation of the selling utilities system when the utility is operating responsibly, for example, unanticipated power flows threatening stability of the system;

3. scheduled maintenance; and,

4. violation of an important term or condition of the arrangement by other parties to the arrangement.

Nonfirm service, on the other hand, is service which the selling utility can interrupt at any time at their discretion. In the sample, the two types of service were almost equally represented. There were 27 firm arrangements and 26 nonfirm arrangements.

The major concern with respect to the type of service offered is the effect of the efficiency goal. Because of the long-term nature of some of the firm arrangements, adjustments to new conditions may not occur as rapidly as efficiency may require.

Table ES.1. Compensation methods/specific fixed rate forms for firm and nonfirm transmission services filed with FERC.

Compensation Method/ Specific Fixed Rate Form	Transmission Service: Firm	Nonfirm	Total
Annual charge	5	0	5
Monthly charge	15	2	17
One-part	106	39	145
Two-part	1	0	1
Mileage	28	0	28
Declining-block	1	0	1
Time-of-day	1	0	1
Split-savings	0	1	1
Banking	1	42	1
TOTAL	158	42	200

Table ES.2. Compensation methods/specific fixed rate forms for firm and nonfirm transmission services filed with non-FERC agencies.

Compensation method/ specific fixed rate form	Transmission service		
	Firm	Nonfirm	Total
Annual charge	0	0	0
Monthly charge	12	0	12
One-part (Tariff)	13	29	42
One-part (Rate Schedule)	81	31	112
Two-part	6	1	7
Mileage	3	0	3
Declining-block	0	0	0
Time-of-day	0	0	0
TOTAL	115	61	176

Also, the limited types of service that are offered may have a dampening effect on the free trade of bulk power.

ES.10.2 Compensation Methods and Rate Forms

Among the firm wheeling arrangements almost two-thirds were one-part, specific rates based on kW's. The remainder of the arrangements were divided among the various rate forms. Three used a one-part rate form based on kWh's. The most interesting method of rates were those of the power pools in which either no charge was made or the charge did not accrue directly to the purchaser of wheeling services.

Approximately one-third of the nonfirm wheeling arrangements were one-part rates based on kWh's. Surprisingly though, another third were one-part rates based on kW's. As in the case with firm arrangements, the remainder of the arrangements are divided between the other rate forms. The power pools also have examples of no direct compensation for wheeling services.

With few exceptions, the arrangements are cost-based and, therefore, to some extent meet the goals of efficiency, revenue requirement, and fair cost apportionment. However, with one exception, the rates are not based on load flow studies and the basis for determining the cost basis may not be strong.

ES.10.3 Specific Requirements for Service

The specific requirements for service can be divided into four areas:

1. Entities eligible for service;

2. Connection requirements;

3. Delivery voltage, and,

4. Special Equipment costs.

Connection and voltage requirements specify which interconnections flows of power must follow and the voltage that must be used at

those connections. Approximately 30 percent of the arrangements limit interconnections to two (one at the receiving and one at the delivery points), while 20 percent limit deliveries to one specific voltage. Often, a number of interconnections and voltages are specified. As with limitations on entities eligible for service, goals can conflict. In this case, efficiency requires that bulk power sales not be constrained, while practicality recognizes that some limitations are necessary. If there are many interconnections and voltage delivery points, the effects on the wheeling utility would appear difficult to determine. However, since so many utilities specify multiple connections and voltages, this may not be a problem.

To obtain wheeling services, utilities are sometimes required to purchase and install special equipment. Examples are transformers, switches, capacitors, or meters. Few of the wheeling arrangements specify the equipment required, but rather specify the party is responsible for the cost of the equipment. Even so, only 25 percent of the arrangements mention such costs. Of the arrangements which do specify who will pay these costs, almost half specify the buyer of the power or wheeling services. If the equipment is used solely for wheeling services, efficiency and fair cost apportionment would require the entire amount be paid by the firm purchasing wheeling services. However, as is true for most transmission equipment, other transactions use and benefit from the equipment. These joint costs should be distributed among the users of the equipment in a manner similar to other transmission equipment.

ES.10.4 Notice and Response Requirements

Notice and response requirements allow for the orderly phase in or phase out of wheeling transactions. They allow the utilities to plan and adjust their systems to the new transactions. However, it is possible that they may also be used to limit access to transmission facilities. For example, in very short-term power purchases it may be crucial to have the wheeling services available quickly. Delays in arranging these services may prevent the power purchase from taking place. The major types of notices and response requirements are:

1. Notice by buyer for initial start of service;

2. Response by seller for initial start of service;

3. Scheduling notice for transactions;

4. Notice for interruption of scheduled service; and,

5. Notice for permanent termination.

The two most important notice requirements are scheduling notices and notices for interruptions. Scheduling notices inform the wheeling utility of the amount of power and the time period during which the power will actually be wheeled. Most of the wheeling arrangements mention these two types of notices. However, as in the case of the other notices, the language is usually vague. "Scheduling notices should be given promptly" and "reasonable notice should be given for interruptions" are common phrases in the arrangements.

The final type of notice, termination notice, is the time period (or in some cases the date) after which the wheeling arrangement will be ended. As is true of other types of notices, few arrangements actually mention this. Those that do usually specify exactly the time period required. The most common time period is six months. If efficiency requires the elimination of constraints on buying and selling of power, then termination notices by their very nature would interfere with efficiency.

ES.10.5 Miscellaneous Requirements

Miscellaneous requirements in wheeling arrangements include limitations on the type of power that can be wheeled, losses and reactive power clauses, and other special terms and conditions which may be in the arrangements.

ES.11 Alternatives to Existing Wheeling Arrangements

This research has identified a number of terms and conditions for wheeling arrangements that could increase the effectiveness of regulation, relative to the goals regarding revenue requirements, efficient use, fair cost apportionment, and practicality and feasibility. The first three goals should receive higher priority than the last, because actual demonstrations must be undertaken to accurately determine the practicality and feasibility of a particular wheeling arrangement methodology.

ES.11.1 Type of Transmission Service

In most cases, present arrangements are divided between firm and nonfirm types of service. However, the degree of firmness in some nonfirm arrangements varies. In a number of arrangements, restrictions are placed on the ability of the wheeling utility to interrupt service. All types of arrangements have strengths and weaknesses when evaluated according to the regulating criteria.

Alternatives to these types of arrangement fall into two broad categories: (1) extending the existing two types to a variety of types; and, (2) dropping the designation of types. Under the first category of alternatives a variety of new types can be developed. A limited addition would be to add conditionally firm (or nonfirm) to the categories. A further addition would be to add conditionally firm (or nonfirm) to the categories. A further addition would be to add strictly firm where the wheeling utility would be required to construct new capacity if needed for the transaction. Finally, the number of arrangements could be extended by categorizing conditionally firm into various subcategories based on their degree of firmness.

These alternatives are the same or similar to existing arrangements with the exception of strictly firm. Each adds to the options available. Efficiency may be increased if transactions were prevented in the past due to a failure in consideration of these types of arrangements. Adequacy and fairness are not applicable to the type of arrangements because they are concerned primarily with prices. Practicality is applicable especially with regards to strictly firm service. Strictly firm may not receive wide acceptance because the buying utilities may prefer joint ownership projects so that more control of transmission facilities are maintained and they can include the facilities in their rate base.

The second broad category alternative for wheeling arrangements is the elimination of types. Existing arrangements guarantee price but service has differing degrees of firmness. The price, for a particular type of service, may be still applicable but at certain times (with certain types, conditionally firm and nonfirm) service cannot be obtained.

In the first alternative of this type, service is always guaranteed but price varies. When demands approach capacity, rather than allocating capacity based on the supply of service it would be allocated by price. This type of pricing is sometimes called "spot market" pricing.

The price adjusts continuously to reflect the cost of supplying the service. Therefore, the price is equal to marginal cost and efficiency is realized. Two major problems exist in the practical implementation of this type of wheeling arrangement. The first is the determination of prices. Accurate measurement of marginal cost may be difficult to achieve. For small, infrequent transactions, this may not be cost effective. The second problem is the large variation in price that may have to occur to balance demand and capacity. In the short-term demand may be very inelastic requiring substantial price jumps to balance the system. Alternatively, as with existing nonfirm types of arrangements, substantial costs may be incurred for standby generation for the utilities buying power in order to avoid incurring sharp jumps in wheeling rates.

A variation on guaranteeing price versus guaranteeing service would be to have all wheeling service nonfirm and then have a futures market for the reliability of that service. By this method the users of wheeling service could choose the degree of firmness in price and reliability of service not only from the supplier of wheeling services but also from other parties.

ES.11.2 Compensation Methods and Rate Forms

The most common existing compensation method is a specific fixed rate. Rates are determined by a fully allocated cost methodology. Often the contribution to the peak determine capacity cost allocation. Alternatives to this existing compensation methodology can be divided into two categories: (1) market pricing methodologies; and, (2) differing cost allocation methodologies.

ES.11.2.1 Market Pricing

Under the first category, market pricing, there are two alternatives: (1) spot market pricing; and, (2) futures market arrangements. Although time varying rates exist, continuously variable wheeling rates or rates that allocate capacity (when capacity limits are reached) by instantaneous changes in rates were not found in existing arrangements. In spot market pricing, rates are set so that marginal costs are covered; then, if demand approaches capacity, rates are raised so that capacity is not exceeded. By this method only the most valued uses can afford and use the capacity. Efficiency in the use of the service is therefore achieved, though adequate revenues may not be generated without a two-part rate. Fairness is achieved because no subsidies are occuring. At each point in time each user is paying

at least the marginal cost of service, though when capacity is tight along some lines, different prices may be paid depending on the effect a particular customer's load has on the system.

ES.11.2.2 Futures Market Prices

The second alternative under the category of market pricing is the nonfirm arrangement with futures markets for the degree of firmness. In this situation two prices exist for two services being provided, the actual wheeling services and the reliability of that wheeling service. The two prices cause the best use to be obtained for both services and the efficiency criterion is satisfied. Since there are no subsidies being produced, fairness is maintained. As in the previous alternative, however, adequacy and practicality are not assured.

A final alternative under differing cost allocation alternatives, similar to the previous cost allocation scheme, is partially allocated costs. Transmission systems provide other services besides the simple transfer of power. Foremost among them is an increase in reliability and voltage stabilization especially to the utility whose service area the lines transect. It has been argued that these other uses should pay a share of the costs of the system. Hence only a certain percentage of the costs are allocated to transmission services.

ES.11.3 Specific Requirements for Service

Specific requirements for service include requirements on entities eligible for service, connections, voltages, and the cost for special equipment. Because tariffs are fairly uncommon in wheeling arrangements (and even then, limitations are placed on eligibility), usually the wheeling arrangement specify that only a certain entity is allowed service. Additionally, those entities are sometimes limited on the service they may obtain (such as the direction of power flows). An alternative to these limitations would be to treat transmission service as common carriers. Under this arrangement, any entity desiring any type of service will be served if capacity is available. If capacity is approached, rationing could be on a first-come first-served or a price basis.

ES.11.4 Notice and Response Requirements

Requirements under this category include: the notice by buyer for initial start of service; the response by seller for initial start of service; the scheduling notice for transaction; the notice for interruption of scheduled service; and the notice for permanent

termination. In general, notice and response requirements are not formalized in a document but are orally agreed upon by the parties involved. Notice and response requirements are needed to be able to plan for expected power flows. Alternatives to existing practice can either be more restrictive or less restrictive. The more restrictive notice and response requirements become, the more probable that some short-term wheeling transactions will not be able to occur. Therefore, improvements would come if the notice and response requirements could be shortened.

To take full advantage of spot market pricing short notice requirements are essential. If prices are changing at five-minute increments, utilities must be able to adjust quickly to avoid unnecessary costs. Implementation of spot market pricing would require computer simulation of the system to determine costs. This same computer simulation would alleviate the need for longer term planning in the system.

Efficiency would be heightened because the most advantageous transactions, even if extremely short-term, could have the opportunity to gain access to the transmission system. If this occurs, the system will be put to its best use thereby increasing efficiency. The practicality of implementing such a computerized system is still questionable and further research is needed for implementation, but recent advances in computer systems should enable the system to be implemented.

A common carrier system would also benefit from increased responsiveness to short-term transactions. Because the eligibility type of service would be expanded, various new short-term transactions may be requested. If they could be served through shorter response then efficiency would be increased.

ES.11.5 Miscellaneous Requirements

Miscellaneous requirements include requirements on the type of power which can be wheeled, special terms and conditions not discussed elsewhere (usually arrangement specific); loss adjustments; and reactive power factors.

ES.11.5.1 Type of Power

Almost half of the arrangements place restrictions on the type of power which can be wheeled. Generally, the restrictions help stabilize the transactions to allow for better planning. An alternative to this restriction is to not specify the type of power which can be wheeled. With increased planning capability

under spot market pricing and common carrier systems, the necessity for increasing certainty through having corresponding wheeling and power arrangements will be decreased. The elimination of these restrictions would increase efficiency because some transactions may occur which would otherwise be restricted.

ES.11.5.2 Adjustment for Losses

A majority of wheeling arrangements mention how losses are calculated. Usually they are based on system average losses. Losses vary according to the loads (kW's) on particular transmission lines. Since loads are continually changing, losses are continually changing. Near the capacity limits of a line losses can be substantial.

An alternative to the use of average system losses is to simulate the system and determine the losses between the receiving and delivery point (or points) for the wheeling transaction. Because losses are so specific to a particular transaction this method gives a more accurate representation of the actual losses involved in a transaction. Efficiency would be increased under this method, though for small transactions it would likely not be practical.

Another alternative is continuously simulating the system to determine losses. Because losses are continuously variable, this method would produce more accurate information about marginal costs. For spot market pricing continuous simulation would be necessary for the accurate performance of the system. Because at all times price would reflect cost, efficiency would be further increased from the previous alternative. Practicality for small isolated transactions, however, becomes more questionable.

ES.12 Conclusions

The study has four major findings. The first is that there is a serious lack of uniformity among wheeling arrangements. Each arrangement is developed by the parties to the arrangement and reflects the individual situations of the parties involved. No one agency regulates all transactions, and even those regulated by FERC are different because FERC does not require uniformity among arrangements. The second major finding is that it is difficult, if not impossible, to determine whether the arrangements meets the terms of the stated regulatory goals. Few utilities perform detailed marginal cost analyses, although some cost information is

available. Without analyses of marginal costs one cannot determine if rates are efficient or fair.

The third finding is that the arrangements usually satisfy the practicality and feasibility objectives. Although other regulatory goals may not be met, at the present time, there is no doubt that the arrangements are working. A considerable amount of power is transferred under these arrangements, producing large cost savings to the utilities involved and their customers.

Finally, wheeling arrangements can be designed that meet the regulatory goals. The suggestions listed above are intended to assist in this design. However, it should be stressed that little empirical information as to costs is currently available, and without this information, it will be difficult to impliment some of the suggestions made above. Therefore, care should be taken in the implementation of improvements. If changes are undertaken inappropriately, they could lead to reductions in bulk power sales. Given the apparent success of the arrangements reviewed for this study, such reductions would likely be costly to the electric power industry.

Chapter 1

Introduction

1.1 Purpose of the Study

The purpose of this study is to examine existing wheeling arrangements to determine their content, to analyse the arrangements to see how close they come to meeting regulatory goals, and finally, to suggest ways that they can be improved. The regulatory goals that are considered are: is economic efficiency promoted, are the costs fairly apportioned, does the arrangement meet the revenue requirement of the wheeling firm, and, is the arrangement practical and feasible to implement? These goals will be referred to as efficiency, fairness, adequacy, and practicality respectively.

1.2 Definitions and Background

There are many definitions of power wheeling transfer services in the literature. These definitions and their rationale and problems are discussed in Chapter 2 of this document. In this report, wheeling is limited to a narrow definition to differentiate it from other types of transactions in which utilities engage. It is defined as the simultaneous transfer of electric power through transmission facilities owned by a utility that was not generated by and is not intended for final use or final sale to an end-use customer of that utility. The phrase "simultaneous transfer" limits wheeling to those transfers where the receipt of the power by the wheeling utility on its lines occurs at the same time as the delivery of power to

the utility buying the power, or another wheeling utility. In addition, we will only consider as wheeling those transactions which are considered transmission service by all parties involved. This would eliminate situations where a utility is simultaneously buying and selling power but the buyer and seller of the power consider the transaction only as a simple power sale or purchase from the first utility.

Typically, a wheeling transaction requires an agreement between the utilities involved in the transaction. An agreement for one type of wheeling service will be referred to as a "wheeling arrangement" in this document. The agreement may be a separate document but often it is part of a larger document which may contain power sales agreements or agreements for different types of wheeling services. The arrangement may be between two utilities (a bilateral arrangement), or among a number of utilities (a multilateral arrangement).

An example of a bilateral arrangement is when a utility (Utility A) owns a remote generating unit or part of a generating unit in another utility's (Utility B) service area. Rather than building its own lines from the unit, Utility A may arrange to have Utility B transport its power across Utility B's lines. Multilateral arrangements can occur when a number of utilities want to exchange power not all of which is directly interconnected. Again, rather than construct special lines to connect all possible combinations they may enter into an agreement among themselves to transmit power for one another. A power pool is an example of this type of arrangement.

The arrangements usually specify specific terms and conditions under which the wheeling service will take place. The terms and conditions can be categorized into five areas:

1. type of transmission service available;

2. compensation methods and rate forms;

3. specific requirements for service;

4. notice and response requirements; and,

5. other miscellaneous requirements.

Because the arrangements involve sales between utilities, most arrangements involving investor-owned utilities are regulated by the Federal Energy Regulatory Commission.

1.3 Importance of Wheeling Transactions

Currently, many utilities have a surplus of generating equipment and a non-optimal capital stock of generating equipment given present cost structures. This problem has been mainly caused by the substantial rise in oil prices in the last decade and the general rise in all energy prices, due partly to the increase in oil prices. Existing oil plants have become uneconomic to operate compared to coal units. Increased prices for electricity have reduced or eliminated the growth in electricity usage. Utilities have recognized the cost savings that could accrue if power sales between them were made. Those with excess capacity in low cost plants can sell power to those utilities experiencing an increase in demand or those wishing to displace high cost generation. The growth of inter-utility power sales has therefore been strong throughout the last decade, amounting to 26 percent of all power produced in the United States. Since the power must be delivered, wheeling services are often needed for power sales, and the growth in wheeling services has been very strong. The recent discussions about deregulation of the electric power industry have also created a strong interest in transmission services and wheeling services.

Due to the large economies of scale associated with power transmission (discussed in Chapter 3), such transmission is a classic example of a natural monopoly. Regulation of such monopolies can usually lead to greater efficiency and welfare gains for society. In order to achieve these gains, though, the regulation must achieve certain goals. These goals are the revenue requirement, the efficient use, the fair cost

apportionment, and the practicality and feasibility objectives. If these goals are not met, welfare may be seriously reduced. This report focuses on describing the current state of regulation of wheeling transactions, analyzing how they meet these goals of regulation, and suggesting possible changes that would bring us closer to these goals.

1.4 Organization of the Report

This report is organized into five chapters and four appendices. Chapter 2, "Technical Effects and Costs Encountered by an Electric Utility Providing Wheeling Services," explains in fairly non-technical terms, the physical aspects of power transmission and interchange between utilities. Chapter 3 is concerned with the economic and regulatory aspects behind power wheeling and is entitled: "Economic Aspects of Wheeling."

Once the background of wheeling is established, existing wheeling arrangements and major regulatory or judicial hearings are described and analyzed. This occurs in Chapter 4, "Existing Wheeling Arrangements." Chapter 4 makes use of Appendices I through IV where the subject is dealt with in more detail. Finally, Chapter 5, "Alternatives to Existing Wheeling Arrangements," describes and evaluates alternatives to existing wheeling arrangements and ties together the previous chapters by suggesting how wheeling arrangements should be structured to move towards achieving the regulatory goals.

1.5 Summary of Findings

There are basically four major findings of this study. The first is that examination of the wheeling arrangements shows that there is a serious lack of uniformity among wheeling arrangements. Each arrangement is developed by the parties to the arrangement and reflects the individual situations of the

parties involved. No one agency regulates all transactions, and even those regulated by FERC are different since the FERC approves these arrangements on a case-by-case basis, and does not require uniformity among all arrangements.

The second major finding is that it is difficult, if not impossible, to determine whether the arrangements approach certain goals of regulation. Few utilities perform detailed marginal cost analyses of the transactions although some cost support is provided. As Chapter 2 details, without such analyses of the marginal costs one cannot determine if rates are efficient or fair.

The third finding is that the arrangements usually satisfy the practicality and feasibility objectives. Although the other regulatory goals may not be met, at the present time the arrangements seem to be working. A considerable amount of power is transferred under these arrangements producing large cost savings to the utilities involved and to their customers.

Finally, wheeling arrangements can be designed to ensure that the regulatory goals of efficient use, fair cost apportionment, and achievement of the revenue requirement are met. However, without further research to determine the feasibility of this design, care should be taken in its implementation. Interference with the present method may prove costly if they lead to reduced bulk power transfers.

Chapter 2

Technical Effects and Costs Encountered by an Electric Utility Providing Wheeling Services

2.1 Introduction

The purpose of this chapter is to discuss the technical effects and costs imposed by a wheeling operation on a utility providing wheeling services. Because there does not seem to be a generally accepted definition of wheeling throughout the electric utility industry, the following definition is proposed:

> An operation will be classified as wheeling if it involves an agreement between two or more separate electric utilities, and power system facilities, and involves the simultaneous transfer through transmission facilities owned by one of those utilities of electric power that was not generated by and is not intended for final use or final sale to an end-use customer of that utility.

Inadvertent wheeling transactions will not be considered as wheeling. For example, at a particular time a utility may be buying and selling power to different utilities. However, only if the transaction is planned as a wheeling transaction among all parties, will it be considered wheeling.

Wheeling can be used in any of the various types of power transfers that occur in the electric utility industry, such as transfer for:

- Economy
- Load diversity

- Displacement of oil-fired generation

- Delivery of power from a remotely located generator

- Purchase of generating capacity

- Emergency.

A separately defined financial charge will usually be assessed for wheeling services.

There are several types of wheeling service:

Firm — Wheeling will not be interrupted by the wheeling utility except under certain extreme conditions such as equipment failure, system reliability problems, or failure of the wheeling customer to comply with the terms of the wheeling agreement.

Conditionally interruptible — Wheeling can be interrupted under additional specified conditions, usually the need for transmission capacity for other purposes.

Unconditionally interruptible — Wheeling can be interrupted at any time for any reason.

Emergency — This type of wheeling may be firm or interruptible, depending on the agreement among utilities.

In order to determine appropriate rates for wheeling operations, it is necessary to estimate the costs incurred and benefits realized by the wheeling utility as a result of the operation. This chapter will therefore address the question:

> Given a certain group of power systems and a set of possible wheeling operations involving those systems, how can the effects of these operations on the wheeling utilities be analyzed and quantified, and to what extent can these results be applied to other situations?

The answer to this question can be summarized:

> To determine how a power system will be affected by a specific wheeling transaction, investigate the operation of the system first as it would be without the wheeling transaction, then as it would be if the transaction does take place. Comparison of the two different modes of operation will show the effects of that particular wheeling transaction.

Conventional tools of power system analysis will be used to evaluate wheeling operations. These tools will also be used to address specific questions:

- Is a proposed wheeling operation technically feasible?

- Which power systems will be affected by the operation?

- To what extent are various portions and elements of affected systems involved?

- At how many locations should the wheeled power be delivered to the receiving utility?

- At what voltage level should delivery be made?

- Are there other technically or economically advantageous ways to accomplish the wheeling objectives?

To answer these and other questions, the operation of the power systems involved can be investigated under each alternative, and the results compared, to assess the advantages and disadvantages of each arrangement.

This chapter begins with a basic discussion of an electric utility power system as it relates to wheeling. This includes discussions of alternative systems, system components, important aspects of system control, and some basic concepts of power system operation. Power system analysis techniques will then be addressed, and finally a treatment of wheeling, feasibility requirements, and use of the analysis techniques for determining costs will be discussed. An appendix that briefly outlines electric power fundamentals and provides further references

follows the main body of the chapter. A glossary of terms is also provided.

2.2 The Electric Utility System

Before beginning any discussion of wheeling, it is important to establish a basic understanding of electric utility systems. A wheeling operation can have various effects on any of the parts of a utility system. Also, a given operation will have different effects on different systems. The purpose of this section is to describe the parts of a utility system, their functions, and the basic operation of the overall system.

An electric utility power system can be functionally divided into two basic parts, generation and delivery. Generation refers to electric power production plants, (coal-fired, nuclear, hydroelectric, etc.) where energy in various forms is converted to electrical energy. The other part, the delivery system, carries power from the generator to the electrical loads served by the power system. The delivery system includes what are commonly referred to as the transmission, subtransmission, and distribution systems.

Either of the two basic parts can be affected by a wheeling operation, and costs may be incurred due to any of these effects. Generation may be affected by changes in optimal unit commitment or economic dispatch[1] caused by the wheeling operation, and power flows on the delivery system will be altered by wheeling.

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1. For further discussion of optimal unit commitment and optimal economic dispatch, see Ref.5; Ref. 6, Ch. 10; and, Ref. 8, Ch. 8.

2.2.1 Power System Reliability

Any of the effects of wheeling have a potential effect on the quality of service provided by the wheeling system. Quality of service can be translated into reliability: "The electric power system is considered reliable if it maintains sufficient and properly functioning generating capability and supporting systems to satisfy customer's needs for electricity [1]." Reliability is the basic concept upon which all power system planning and operation is based. The level of reliability at which a particular utility system is to operate is determined by the utility and regulatory authorities. The needs of the customers and indirectly, what they are willing to pay, are considered in making this decision. The reliability of a power system, including generation and delivery systems, can be affected in three ways:[2]

1. The components of the system lack sufficient capacity, or insufficient energy is available to serve all loads even with all components and resources in service;

2. The system fails to serve all loads due to the unavailability of equipment or fuel when needed;

3. The system fails in a dynamic or operating sense even though sufficient installed capacity is available.

The first two modes of failure relate to system adequacy. An adequate system, therefore, has sufficient capacity to meet load and energy requirements at all times. The third failure mode indicates a lack of system security, so a secure system will survive a certain level of disturbance without loss of load.

The costs of increasing the reliability of a system result from the additional equipment necessary and the cost of maintaining

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2. The National Electric Reliability Study: Final Report, U.S. Department of Energy, DOE/EP-0004, April 1981.

additional generating reserves.[3] However, additional costs may also result if reliability is too low. A large manufacturing operation, for example, can incur considerable financial losses during a shutdown caused by electric power outage. The electric utility could conceivably be required to share these losses if the level of reliability provided is below that which was promised or reasonably expected.

2.2.2 Economic Power System Operation

After assessing the necessary level of reliability for a system, the major objective of system operation is to provide that level of reliability in the most economical way. The concepts of optimal generation unit commitment and optimal economic dispatch are used to achieve this objective. Optimal unit commitment calculations, often done on a weekly basis, provide an hourly schedule of the combination of generating units that will serve the forecast load and reserve requirements for the lowest cost (based on generator efficiencies, fuel costs, etc.). Optimal economic dispatch, computed every few minutes, determines the optimal loading (power output level) of each of the committed generators. The objective of economic dispatch is to minimize operating costs by equalizing the individual incremental costs of each operating generator. Economic dispatch is the "fine tuning" of operational costs, based on fluctuations in the system load, incremental generation costs, and power losses within the system.

2.2.3 Power System Simulations

In order to predict a system's performance under specified conditions, computer models that simulate operation of the system are used. These simulations can be the basic tools in

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3. Generating reserves refers to generating capacity in excess of that amount needed to serve the systems loads. Installed reserves is the total amount of excess capacity that exists on the system, and spinning reserve is that amount which can be brought into service quickly when additional power is needed.

the evaluation of proposed wheeling operations. Two types of simulation programs are commonly used: load flow and stability. The output of a load flow program describes the conditions on a system at one point in time, while a stability program provides details of a system's operation over a certain period of time. Both can be important in a wheeling analysis.

2.2.3.1 Load Flow Studies

Load flow refers to the flow of power on a system from generator to load (see Appendix, Section 8 for discussion of the concept of power flow). The distribution of load flow among various paths is dependent on the configurations and control of loads, generation, and the delivery system. If the controls or configurations are altered, load flow will be redistributed. The primary objective of a load flow study is to determine what the conditions are on the various delivery paths between generators and loads for a specified set of system conditions.

Several types of load flow programs are available, differing in the amount of detail provided in the solution. The simplest of these is called a dc load flow, because while it is used to analyze an ac system, it considers only real power flow, ignoring the effects of reactive power (see Appendix). Another type, called the single phase ac load flow program, analyzes real and reactive power flows for a single phase system, or for one phase of a three phase system. If the three phase system is then assumed to be balanced (loading is equal on all three phases), the single phase can represent all three phases. The most detailed load flow program is the three phase load flow, in which each phase is separately represented and analyzed for real and reactive flows.

The output of a load flow program provides a list of system conditions including voltages, phase angles, generation loading, load levels, current flows, and power flows at different points throughout the system at a specific instant in time. Other information provided may include line loadings, voltage drops, power losses, line compensation, control settings, and line charging currents.

A load flow study is done by running a load flow program a number of times using varying system conditions. Most load flow programs have provisions for simulating the following changes to the system being studied:

- Add or remove lines and transformers from service.

- Vary load or generation at any point on the system. (This allows simulation of power imports or exports at system interconnection points.)

- Alter conductor or transformer characteristics.

- Add or remove capacitors.

- Change real or reactive power flow constraints between systems.

The use of load flow studies to analyze specific wheeling arrangements is discussed in Section 6 of this chapter.

2.2.3.2 Stability Studies

While load flow programs provide information about a power system at one instant, stability programs simulate system operations over a period of time, and are used to evaluate a system's stability[4] following a disturbance. The disturbance

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4. When the operation of a system is disturbed in some way, either by normal random load variations or by a major disturbance such as a lightning strike or the forced outage of a generator, the system voltage phase angles undergo a transient response in which they oscillate about their steady-state values. If these oscillations fade away and the system settles back to a new steady operating condition with frequency still at 60H., the system is stable. If the oscillations do not fade away but instead increase in magnitude, the system is unstable. The instability will cause loss of synchronism within the system. Protective equipment on the system will electrically isolate motors and generators from the system. If the problem is not corrected quickly. complete loss of service to customers can result. See Ref. 8, Ch. 14; Ref. 9, Ch. 12.

may be normal random load variations, planned system control actions, or a more major unplanned disturbance, such as a lightning strike, a short-circuited line, or a forced generator outage. One type of stability program, the transient stability program, is used in the analysis of major disturbances. A few seconds of operation, usually up to ten, following the disturbance is simulated. Dynamic stability programs, in contrast, simulate a longer time period, up to several minutes and are used to evaluate small or localized disturbances which can slowly propagate through a large area. Both types of stability programs provide information on voltages, phase angles, and system frequency, the important variables in a stability analysis. These quantities will indicate any unacceptable changes in voltage or system frequency, or a loss of synchronization among system components.

The use of stability studies in wheeling analyses is discussed in Section 6.

2.2.3.3 Use of Simulation Studies

Many of the day-to-day operational decisions of a utility are made based on past experience of the utility in operating its system. It is when a new situation occurs that load flow and stability programs are needed. New situations could include:

- Additional loads to be served
- New generation capacity
- New transmission or distribution lines
- Additional loading on existing lines
- Loss of facilities
- Wheeling.

The process by which new situations are analyzed is an iterative process. A forecast of system loads and needed reserves for the

new situation is made, and from that forecast a unit commitment schedule is derived. Using optimal economic dispatch criteria, a potential system configuration is then determined. This configuration is tested using the analysis programs. Load flow results indicate whether voltages and power flows remain within specific limits, and stability programs indicate whether or not the system will remain stable under normal conditions and during certain specified contingencies (loss of generation, faulted lines, etc.). If any of the criteria are not met, then an alternative configuration is determined, and the analysis process is repeated. Operating experience and engineering judgment are major parts of the process. It may be clear to the system operators that certain changes to the system will impact it in certain ways, thus reducing the number of times the analysis programs must be run. However, the only way to accurately quantify the effects are either to actually make the changes and closely monitor the system, or to use the simulation programs. When the impacts to the system may be major, simulation is a much safer approach.

2.2.4 The Power Delivery System

2.2.4.1 Functions of the Power Delivery System

Since a wheeling operation will always affect the delivery system of the wheeling utilities, an understanding of the functions of this system will be helpful in understanding the effects of wheeling. The primary purpose of the electric delivery system is simple:

1. The purpose of the electric power delivery system is to electrically connect generators to loads. Beyond this primary purpose, an electric power line may serve two other functions:

2. To improve system economics, and,

3. To increase system reliability.

All functions and benefits of a given line will fall into one or more of these three categories.

The electric power delivery system is often conceptually divided into three subsystems: transmission, subtransmission, and distribution. Transmission usually refers to those lines used to transfer bulk power (those lines interconnecting generators or large systems, for example). Distribution lines are commonly one voltage level above the utilization voltage; for example, one step above 240 V for residential distribution. Subtransmission, then, is everything between transmission and distribution.

For the purpose of this report, a classification based only on the functions a line serves, and not its voltage level, will be used. Some of these functions can apply to more than one of the three usual subsystems.

The classification system to be used will define the functions of a line and the benefits (economic or reliability) which may result from each function. It is important to remember that every electric power line directly or indirectly has the basic function of connecting generators to loads. This function can be subdivided into one or more of the following functions for a specific line:

1. Connect a generator to the main power grid;

2. Interconnect separate power systems;

3. Distribute among and deliver power to customers; and,

4. General system integration - lines which provide an interface between the above three functions (e.g. connect generator lines with distribution lines, connect two generators, etc.).

A line will often perform several of these functions. Consider, for example, a high voltage transmission line that connects a remotely located generator to the main power grid. The line's right-of-way takes it past a large industrial plant, and the

plant's power system is fed directly from the high voltage line. This line, then has two functions:

1. Connect a generator to the main power grid.

2. Distribute among and deliver power to customers.

This is not the usual concept of distribution line - they are usually low voltage lines--but functionally, the line is distributing and delivering power.

The functions of a line may change over time. Consider again a line connecting a generator to the main grid. Suppose now that another utility purchases part of that generator's capacity and constructs a line to it. This line and the existing line now have a second function: interconnection of separate systems.

A line performing one of the delivery functions can provide certain benefits to the power system. These benefits, outlined below, will affect either system economics or reliability.

Function: Connect generator to main power grid.
Possible benefits:
Economic:

- o Allow generator to displace other higher cost generation.
- o Relieve loading on heavily loaded lines, reducing losses in those lines.
- o Reduce the distance power must travel from generator to loads, thus reducing line losses.

Reliability:

- o Relieve loading on heavily loaded lines to provide a greater stability margin.
- o Reduce distance power must travel from generator to load, thus lessening possibility of loss of service due to equipment failure.
- o Provide a parallel or alternate path for power to flow, so if one path fails, the other will still transport the power.
- o Improve the generator's stability.

o Increase system reserves.

Function: System Interconnection.
Possible benefits:
Economic:

o Economic energy exchanges.

o Reserve sharing.

o Diversity exchanges.

o Economies of scale in generation construction.

o Reduce losses on other interconnections.

o Central economic dispatch.

o Coordinated maintenance outages.

o Improved utilization of available plant sites.

Reliability:

o Reserve sharing.

o Emergency power exchanges.

o Provide a parallel or alternate path for power flow.

o Reduce loadings on other interconnections to provide a greater stability margin.

o Shared effects of power shortages (load shedding, voltage reduction).

o Coordinated maintenance outages.

Function: Distribute and deliver power to customers.
Possible benefits:
Economic:

o Reduce losses on other lines.

o Allow access to cogeneration or other distributed generating sources.

Reliability:

o Provide parallel or alternate power flow path.

o Reduce loadings on other lines to provide greater stability margin.

Function: General system integration.
Possible benefits: System integration may provide or enhance any of the benefits derived from the other functions. In addition, system integration may provide the following:
Economic:

o Reduce losses on other system integration lines.

o Reduce the distance power must travel, thus reducing line losses.

Reliability:

o Reduce loadings on other lines to provide a greater stability margin.

o Reduce the distance power must travel.

o Provide a parallel or alternate path for power flow.

The benefits outlined above usually increase as new facilities are added to a utility's delivery system. However, there can also be certain problems caused by expanding the power delivery system:

- Disturbances on one system are more likely to be transferred to another over strengthened interconnection lines.

- Complexity of the overall system increases and control becomes more difficult as new lines are added.

While the benefits of increased electrical strength of connections usually outweigh the disadvantages, it is still important to consider these possible negative effects.

A wheeling operation can affect power lines serving any of the functions described. Which lines within a system will be affected is dependent on the proposed wheeling arrangement and the configuration of the systems involved. For example, a wheeling operation which causes system dispatch to be altered will affect lines serving the generator connection function, and low voltage distribution lines may be affected in the case of

power being wheeled to a small power distributor. The only way to accurately predict which parts of a system will be affected by a wheeling operation, and to what extent, is through system simulation studies.

The purpose of constructing any part of an electric power delivery system is to achieve to some degree one or more of the functions and benefits described. These, then, are the considerations of delivery system planning.

2.2.4.2 Delivery System Planning

Utility delivery system planning consists of two major objectives:

1. Determining which functions and benefits are desired from a particular project, and

2. Designing the optimum system to accomplish these objectives. Planning is an iterative process in which various means of achieving desired results are compared, and technical and economic considerations are balanced.

2.2.4.3 Types of Delivery Systems

Several types of power delivery systems are presently in use. The most common of these for any function is the overhead ac line. The voltage level of an ac line is partially dependent on the function being served. The functions of generator connection and system interconnection are usually served in the range of 100,000 to 765,000 volts (100 to 765 kV). High voltages are used because for a given power flow, the power losses due to the impedance of a transmission line decrease rapidly as the transmission voltage increases. Higher voltage lines also more efficiently utilize the land on which they are located. Distribution and delivery service to customers is usually below 30 kV, although high voltage delivery to large industrial customers is not unusual. The system integration function utilizes a wide range of voltage levels, but most lines in the 30-120 kV range have system integration as one function.

The voltages given here are common for the various functions, but voltage does not determine function. Any of the functions may be served at any voltage.

Underground power lines are sometimes used when overhead lines are not feasible or desirable. Underground lines usually serve the distribution or integration functions, and are primarily used in two applications:

1. In a congested urban area where space for overhead lines is limited, and,

2. In a residential area. for esthetic reasons.

The cost of an underground line is higher than that of a comparable overhead line, and maintenance of the underground line is more difficult. At higher voltages, problems with excessive charging current. poor heat dissipation and increased losses add further to the cost of underground lines. However, these problems can be overcome through the use of advanced insulation and forced cooling.

Another alternative in electric power delivery is high voltage direct current (HVDC) transmission. Presently, HVDC is limited to two-terminal point-to-point transmission, but work is being done to develop dc network systems. In certain applications, HVDC has advantages over ac, including:

- Line losses are lower because there is no reactive power flow. This allows more efficient use of facilities and land.

- Power flow is completely controllable.

- Can allow more efficient use of a parallel ac line.

- Can improve stability of ac systems.

- Allows ac systems to be connected without being synchronized.

- Most two-line HVDC systems can operate at half-power using only one line.

The equipment required at the terminations of a dc transmission line is more expensive than for a comparable ac line. This extra cost must be justified by the benefits of dc. The costs of the solid state components used in HVDC systems is decreasing and the performance of these systems is improving, so application of HVDC transmission should continue to increase.

Other methods of power delivery such as superconducting lines or six-phase transmission are being considered, but only for specialized applications. These methods will probably not see significant use in the near future.

Regardless of what type of power delivery system is used, the techniques of analyzing the effects of any operation, including wheeling, are the same for all systems. When a new type of delivery is brought into use by a utility, models of the system must be available for use in load flow and stability studies. These studies are then used in the usual way to assess the effects of the wheeling operation.

2.2.4.4 Delivery System Components

The power delivery system consists of a wide array of components. These components and the purpose of each will now be discussed in the context of how they are affected by a wheeling transaction. For the purpose of this chapter, if a component is said to be affected by a wheeling operation, it means the operation alters the power flow through that component from what it would be without wheeling. The effects of wheeling are then the effects of the altered power flow. Determining whether or not each component is affected by a certain wheeling operation is discussed in Section 6 of this chapter.

Increased or decreased power flow through a system component will result in a decrease or increase, respectively, in the useful life of that component. While it is possible to estimate this "loss of life" of a component under specified conditions,

the techniques of doing so are extremely complex. Because a wheeling transaction should rarely cause overloading of components, the loss of life due to wheeling should be minimal. Also, power system components are usually not used for their full useful life, but instead are replaced due to obsolescence or because the system has grown beyond the component's capacity.

Conductors — The most basic and commonly recognized components of an electric power system are overhead electrical cables and their supporting structures. There is one energized conductor for each electrical ac phase (three phase conductors in a three-phase system). Phase conductors usually have aluminum strands for electrical conduction and steel strands for added physical strength. Power conductors are characterized by electrical properties of series impedance and shunt admittance. A high voltage transmission line will usually have steel shield wires, connected to ground at each tower, for lightning protection. The preceding discussion of loss of life effects applies to conductors.

Insulation — Insulation is a fundamental concept of power system technology. The purpose of insulation is to electrically isolate the current-carrying components of the system from each other and from the system ground. Glass or glazed porcelain insulators are used to hang conductors from transmission towers. Air, oils, gases, and vacuums provide insulation for other components. Insulation is coordinated with other system protection equipment to provide adequate protection against voltage surges caused by lightning and line switching. The use of lightning arrestors, devices which automatically divert lightning or switching surges to ground, can reduce the level of insulation needed on a system. Power system insulation is affected much more by environmental and other external conditions (weather, air pollution, vandalism, etc.) than by power flows through the components which the insulation protects, so the effects of a wheeling operation on insulation will be minimal.

Transformers — Transformers for ac current are used to obtain the high voltages of bulk power transmission and

then to reduce the voltage back to subtransmission and distribution levels. They are necessary because power cannot be generated or used by the customers at transmission voltages due to insulation and safety problems. Transformers are characterized by the magnitude of the voltage change across the transformer, and by the power losses in the transformer's core and windings. While many transformers are used simply to step voltage up or down, there are specialized transformers available which allow the magnitude of the voltage or the phase angle to be varied during operation. These are used to regulate the flow of real and reactive power and to maintain proper voltage levels throughout the system. The power output of a transformer is equal to the power input minus the losses in the transformer. Transformers of this type will not operate in a direct current system. The loss of life discussion also applies to transformers.

Circuit Breakers

A circuit breaker is a mechanical switch designed to interrupt the flow of current in a power system circuit. When the electrical contacts in the breaker are separated, the arc which occurs is extinguished by a blast of compressed air or by opening the contacts in an insulating medium of oil, gas, or vacuum.

Relays

The decision of when a breaker should open or close a circuit under transient or emergency conditions is made by a relay, a device which detects undesirable conditions and, when appropriate, instructs a breaker to open the circuit. A relay may also be manually or remotely operated by utility personnel to open or close a breaker as part of normal operations. Relays and breakers are used in all functions of an electric power system, from high voltage transmission to low voltage distribution. Breakers and relays must be extremely fast and reliable. They may remain unused for long periods, but must operate without fail when needed. Wheeling will have little impact on breakers and relays, because the life of these components depends more on how often they are operated than on the power flows.

Capacitors

The inductive and capacitive characteristics of an ac power system cause several undesirable effects. The most serious of these is the loading of the system with reactive power. Since reactive power performs no useful work, and since power losses through a line increase in proportion to the square of the increase in both real and reactive power, it is desirable to transport as little reactive power as possible. Reactive power flows can be reduced through the use of shunt capacitive elements (capacitors connected between the power line and ground) located at the proper points in a system.[5] By reducing the amount of reactive power transported by a line, losses in the line are reduced, and the ability of the line to carry real power is increased. Shunt capacitors are also used for voltage regulation and are sometimes switched on and off the system as conditions change. As the amount of power carried by an 8V line increases, it may be necessary to add more capacitors to that line, resulting in an additional cost for wheeling. This is discussed in more detail in Section 5.1.

Substations

A power system substation is an installation where power lines intersect, voltage is transformed, and system protection and compensation are performed. Transformers, breakers, relays, and other equipment may all be contained in a substation. Various substations serve the different functions of the delivery system. Voltage is increased from generation to transmission levels at a generation substation. Voltage reductions and line interconnections are carried out at transmission and subtransmission substations. The distribution system is fed at a distribution substation.

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5. Most loads on a power system have inductive characteristics, and hence are called inductive loads. An inductive load is said to consume reactive power, while a capacitive load is said to generate reactive power. Thus by placing capacitors throughout the system to generate reactive power for the inductive loads, the reactive loading is removed from the transmission lines and generators, increasing their capacities to transmit and generate real (useful) power. See Ref. 8, pp. 20, 224-226.

2.2.4.5 Delivery System Control for Wheeling

A wheeling operation may require control actions by any of the utilities involved. The basic fact on which control of an ac system is based is that power will always flow from an area of excess power to an area where power is needed, and will divide among the various paths according to the availability and accessibility of each path. Thus to control the power flow, the system operators vary the configuration of generation, loads, and delivery, attempting to make the desired paths the most available and accessible. This is done by switching lines, adjusting generation real and reactive power levels, switching capacitors, varying transformer settings, and through various other control techniques.

Power flows are controlled with respect to control areas. A control area is a part of a power system which is controlled from a single location or by a single entity as a single system. Control area boundaries often coincide with boundaries of individual utility service areas, only part of one utility, or all or part of several utilities.

To begin a wheeling operation, the utility that is generating and selling the power increases generation at a specific rate during a given time period, and the utility that is buying the power reduces its generation or other power imports at the same rate. The power then begins to flow from seller to buyer "through" the wheeling system. The wheeling system makes the necessary changes to its system, attempting to obtain a predetermined optimal load flow. At the end of the wheeling period, the process is simply reversed. The buyer increases generation or other imports, the seller decreases generation, and the wheeling system returns to normal operation.

A wheeling transfer must be planned for and recognized by the wheeling system, but there are no operating procedures which are unique to wheeling. The usual generation commitment and dispatch planning methods are used, with the wheeling operation simply being one factor in the overall operations planning

procedure. Similarly, the system must be monitored, as always, to assure that all voltages and component loadings are within normal specified ratings. As loadings approach these ratings, whether due to wheeling or other causes, the system should be monitored closely to insure reliable service.

It is important to remember that the control of power flow on an ac system is not exact. Even with advanced control systems it can still be difficult to control, or even predict, the flows on certain lines. The use of simulation studies and close monitoring of the system are necessary tools of power system control.

The actual physical operations for control of a dc or other alternative transmission system are different from ac system operations, but the fundamental objectives are the same. While power flows are more readily controlled on a dc line, it is ac systems that are connected by the dc line, so the control problems still exist.

2.2.5 Conclusion

The basic structure and operation of an electric utility system has been discussed in this section. It is possible now, using this information, to assess how a wheeling operation will affect a utility system. However, before doing this it is important to develop a detailed definition of wheeling in order to determine if a specified operation is or is not a wheeling operation.

2.3 Definition of Wheeling

2.3.1 Introduction

The definition of wheeling used in this report was presented in the introduction of Section 1:

> An operation will be classified as wheeling if it involves an agreement between two or more separate

> electric utilities, and power system facilities, and if at least one of the utilities transfers electric power that was not generated by and is not intended for final use by that utility or an end-use customer of that utility.

The purpose of this section is to show how this definition was developed, and to further clarify the definition through explanations and examples.

2.3.2 Development of Definition

The definition presented above was developed based on information obtained in discussions with people familiar with the electric utility industry and wheeling operations. From these discussions, a general feeling on the purpose of wheeling seemed to emerge. This purpose can be summarized as follows:

> The purpose of a wheeling operation is to transfer power using facilities owned by a utility other than the utility that generated the power and the utility that used the power or sells it to an end-use customer.

In other words, in any sale of electric power by an electric utility, the power is generated and then at some point is sold to an end-use customer, to another utility for resale, or is used by the utility. One utility may both generate and sell the power, or one may generate and another sell it. Either way, if any utility besides the generating utility and the selling utility helps to transfer the power, then wheeling is indicated.

2.3.3 Methods of Power Transfer

There are a number of different ways that a utility can transfer power and thus become involved in a wheeling operation. All of these accomplish the same result, which is to provide a certain amount of power at a specified point after accepting a similar amount at another point, but the result is achieved in different ways. (For a discussion of the concept of power flows, see Section 8.5)

2.3.3.1 "Flow-through"

The most common and simplest form of power transfer is to have the power simply flow into the wheeling system at the import point, flow directly through the system on the delivery lines that connect the import and export points, and flow back out of the system at the export point. The flows on the connecting lines are the only things affected on the wheeling system. While this situation in reality never actually occurs, it can sometimes be used to represent a wheeling transfer if the transfer is small or if the connecting lines are strong.

2.3.3.2 "Displacement"

For this report, wheeling by "displacement" will refer to any operation in which the import of wheeling power into the wheeling system results in a decrease in other power inputs to the area near the import point. These inputs could be power flows across the wheeling system, other imports, or generation. One example of displacement wheeling is the following four step process:

1. Power is imported by the wheeling system at the import point.

2. Imported power is consumed by end-use customers near the import point.

3. An amount of power equal to that imported is generated by the wheeling utility near the export point.

4. Power is exported by the wheeling utility at the export point.

Thus, the end result of wheeling is accomplished by displacement, just as in the flow-through method, but in an entirely different way.

2.3.3.3 Combinations of Wheeling Methods

In reality, a wheeling operation will always be a combination of the above methods. Some operations, however, will use one method enough to be classified for practical purposes as being entirely that method. Others, though, will use enough of more than one method to require classification as both.

2.3.4 Non-Simultaneous Power Transfers

Another type of operation that could be performed by utilities is non-simultaneous power transfers. These are operations in which power is imported by the wheeling system at one time and is exported at a later time. This introduces a new concept, energy banking. Non-simultaneous transfers are not included in the definition of wheeling because electricity cannot be stored easily and has different characteristics (such as value) at different points in time.

2.3.5 Other Definitions

Two other definitions of wheeling have been provided in the past by the U.S. Federal Power Commission (now the Federal Energy Regulatory Commission). These definitions were used in the development of the definition presented in this report:

> An electric operation wherein transmission facilities of one system are utilized to transmit power of another system. Wheeling service may be accomplished by displacement.[6]

This definition was not used in this report because it implies that wheeling is limited to the transmission facilities of a system. A wheeling operation can affect not only transmission,

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6. Glossary of Important Power and Rate Terms, Abbreviations, and Units of Measurement, U.S. Federal Power Commission, 1965.

but also subtransmission, distribution, and generation facilities.

> Transportation of electricity by a utility over its lines for another utility, also includes receipts from and delivery to another system of like amounts but not necessarily the same power.[7]

The first part of this definition could include a conventional two-party power sale where one utility generates and delivers power to another utility. This is not generally considered to be wheeling, and therefore this definition was not adopted.

2.3.6 Identifying a Wheeling Operation

The definition of wheeling presented in this report can be used to determine whether or not a certain transfer of power should be identified as wheeling. This judgement should be made based on the two major points of the definition:

1. Two or more utilities are involved

2. Power is handled by at least one utility that did not generate it and will not use or sell it to an end-use customer.

If the second point is true for a given transfer, then the first point must also be true. Thus, by answering the following question regarding a given power transfer, a determination of whether or not that transfer should be called a wheeling transfer can be made:

> Does any utility help to transfer the power besides the utility that generated it and the utility that will use or sell it to an end-use customer?

Keeping in mind that the utility that generates the power and the utility that sells it may be the same utility, if the answer to this question is yes, then the transfer in question is a wheeling transfer by the definition presented in this report.

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7. The 1970 National Power Survey, Part I, U.S. Federal Power Commission, December 1971, p. I-24-8.

2.3.7 Examples

Several example cases will now be presented to illustrate the use of the wheeling definition in determining whether or not a power transfer is a wheeling transfer. The blocks in the figures used in these examples represent utility service areas, and the presence of solid lines connecting two blocks indicates that those utilities are electrically interconnected.

2.3.7.1 Three-Party Wheeling

Figure 2.3.1 shows a simple three-party wheeling arrangement. Utility System A wishes to sell power to System C, but A is not directly interconnected to C. However, A and C are connected through System B, so the power is wheeled by System B. Utility System B is the wheeling system in this operation.

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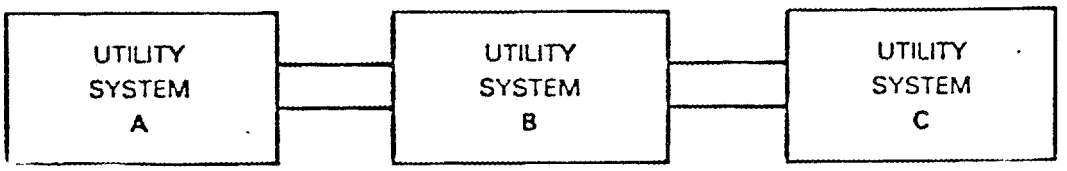

Fig. 2.3.1 Three-party Wheeling

2.3.7.2 Two-Party Wheeling

An example of a wheeling operation involving only two parties is depicted in Fig. 2.3.2. A generator owned by utility B is physically located in utility A's service area, and is connected to System B only through lines owned by A. Therefore, utility B both generates and sells the power for final use, but utility A transfers the power from the generator to utility B's lines, and

thus utility A is the wheeling utility. This can occur with jointly-owned generating facilities.

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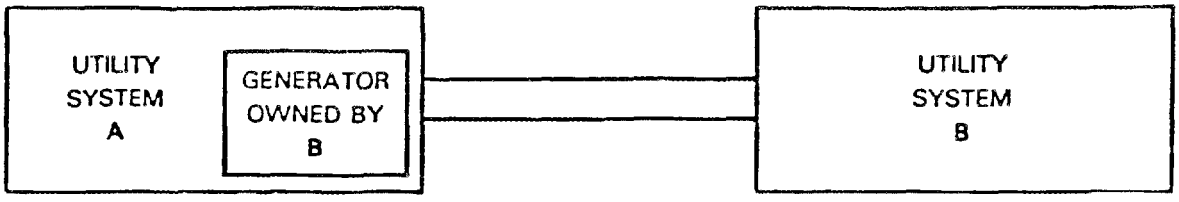

Fig. 2.3.2. Two-party Wheeling

2.3.7.3 Wheeling To a Utility with No Internal Generation

Utility A, shown in Fig. 2.3.3, which owns no generation facilities, normally purchases power from utilities B and C. Utility A now wishes, however, to purchase power from utility D, with which it is not directly connected. Utility C agrees to transfer the power from D to A, and thus becomes the wheeling utility in this transfer.

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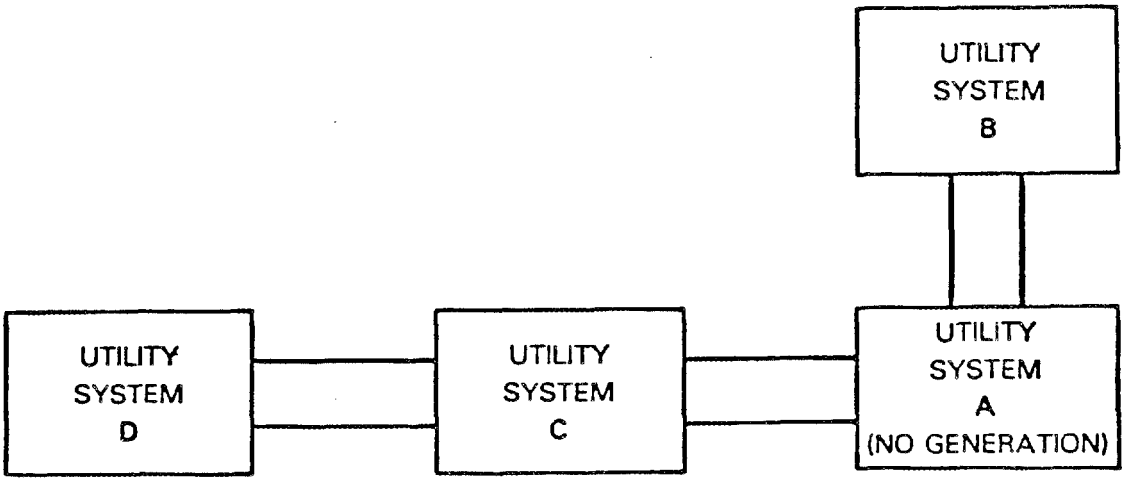

Fig. 2.3.3. Wheeling to a Utility with no Internal Generation

2.3.7.4 Multi-Party Wheeling

Fig. 2.3.4 shows a wheeling transfer with more than one wheeling utility. A power transfer is to take place between systems A and E. Since systems A and E are only connected through systems B, C, and D, all three of these systems are potential wheeling utilities in this transfer.

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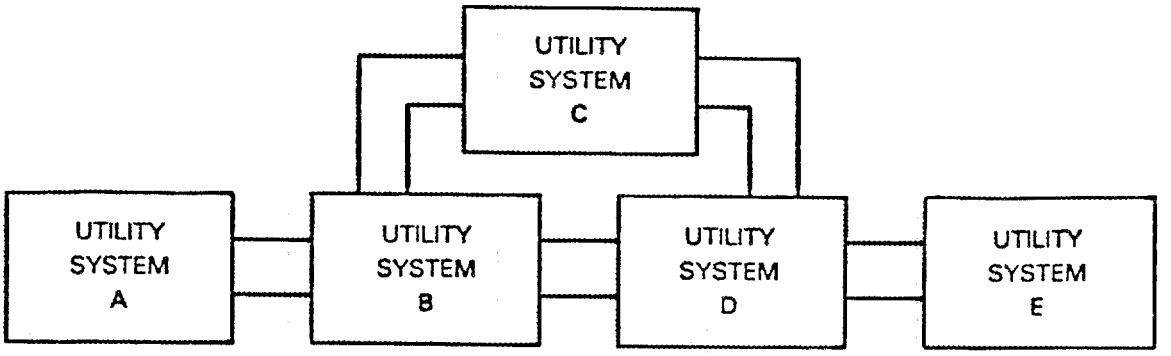

Fig. 2.3.4. Multi-Party Wheeling

2.3.7.5 Non-Wheeling Power Transfers

<u>Two-Party Transfer</u> Figure 2.3.5 represents a simple two-party power transfer, in which utility A is selling power to utility B. Utility A generates the power, and utility B sells it to end-use customers. By the definition of wheeling presented in this report, this is not a wheeling transfer because there is no utility involved in the transfer besides the one generating the power and the one selling it.

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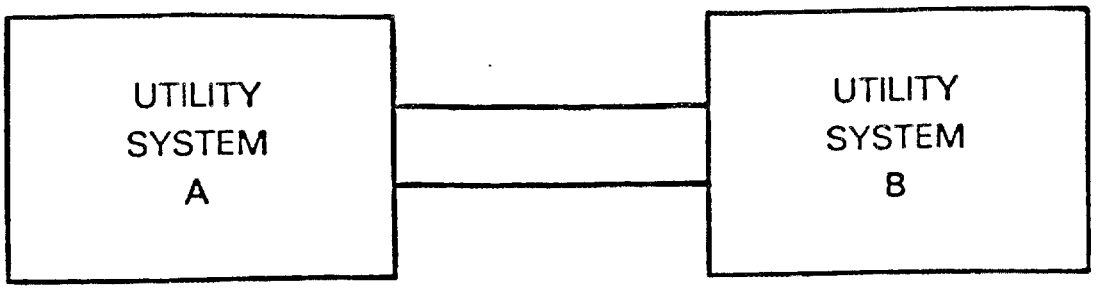

Fig. 2.3.5. Conventional Two-Party Transfer

Combination of Wheeling and Non-Wheeling Transfers Finally, again referring to Fig. 2.3.6, a power transfer that combines wheeling with a conventional power sale is shown. Utility A is delivering 200 MW of power to utility B, and utility B is passing 100 MW, which was sold by A to C, on to utility C. Thus there are two transactions taking place: a 100 MW wheeling transfer between A and C, with B acting as the wheeling utility, and a conventional sale of 100 MW from A to B.

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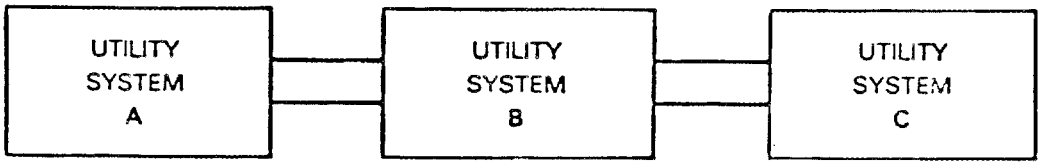

Fig. 2.3.6. Three-party transfers

2.3.8 Conclusion

The definition of wheeling developed in this section and the discussion in Section 2 of the basic structure and operation of a utility system can now be used to evaluate a specified power

transfer operation to determine whether or not it is wheeling, and to determine the possible technical effects of this operation on the utility systems involved. The next section, Section 4, will discuss what effects could be encountered on a system providing wheeling services. The influence of these effects on feasibility and costs of the wheeling operation are then discussed in Sections 5 and 6, respectively.

2.4 Technical Effects of Wheeling

Based on the information in the preceding sections, it is now possible to discuss the possible technical effects that a wheeling operation will have on a utility providing wheeling services. These effects fall into two categories, altered delivery system loading and altered generating unit commitment or economic dispatch. These effects will result in changes in overall production costs for the wheeling utility.

2.4.1 Altered Delivery System Loading

A major effect that a utility will encounter is a change in the loading of its power delivery system. This may affect any of the delivery functions or any part of the delivery system. Some parts of the system may experience increased loading, while on other parts the loading may be decreased. On the parts where loading is increased, there will be an increase in delivery system losses. The costs resulting from these additional losses will be the cost of increased generation or imports to replace the power lost. Likewise, if loading is decreased by the wheeling operations, the losses in the lines will decrease, allowing a comparable reduction in generation or power imports.

Both real and reactive power loading can be affected by wheeling. Real power flows will be affected because real power is transferred across the wheeling system. Reactive power loading can also change because of conditions on the wheeling system, the generating system, or the customer's system.

Provisions may be needed in the wheeling agreement for reactive power compensation on the wheeling system.

Changes in losses on the delivery system can be estimated directly from load flow studies because this is one principal output of a load flow program. However, the costs associated with altered system losses will be determined from changes in economic dispatch, which is discussed later in this section.

Another potential impact of altered delivery system loading is a decrease in the life of current-carrying components (transformers, conductors, generators, etc.). However, since component loadings will usually remain within normal ratings during wheeling, this effect will be small and the complex calculations required for determining loss of life are probably not justified.

Losses on the wheeling system can be accounted for in two different ways. The first is for the wheeling system to simply generate more power to make up for the increased losses. The second is for the wheeling system to subtract the power losses from the power it receives from the selling system. The wheeling system thus delivers less power to the receiving system than it received from the seller.

2.4.2 Altered Generation Unit Commitment or Economic Dispatch

The optimal generating unit commitment or economic dispatch of the wheeling system may be altered by some wheeling operations. Any time power flows in a system are changed, optimal commitment or dispatch may be altered. The changes may either improve or degrade operating economics of the system. The costs or benefits due to these changes arise from the varying operating costs between generators (fuel costs and unit efficiency) and also on the line losses along various delivery paths. These costs can be quantified using the wheeling utility's production costing methods.

There are several instances in which a wheeling operation will affect generation on the wheeling system:

- When power flows on a system are sufficiently altered by wheeling to make a new distribution of power flows necessary for economic reasons (This is altered economic dispatch.)

- When increased power losses caused by wheeling are compensated for by increasing generation on the wheeling system.

- When wheeling causes certain lines to be loaded to their limits, making it necessary to redistribute the power flows on the wheeling system.

- When wheeling is to be accomplished by the displacement, discussed in Section 3.3.2.

2.4.3 Changes in Production Costs

In this chapter production costs are the variable operation and maintenance costs incurred by a utility to produce a certain amount of electric power. Relatively fixed costs such as depreciation and routine structural maintenance are excluded. Every utility has its own techniques for determining production costs, but the differences in these techniques are in the amount of detail used. Some use detailed production analysis programs, while others compute costs using relatively simple formulas. The factors affecting production costs are the same for all utilities - availability of generating resources, generation efficiency, fuel costs, and line losses. Thus, any change in any of these quantities is reflected in production cost results. The costs of a specific wheeling operation may be evaluated by using the wheeling utility's production cost models and formulas to compare the cost of normal operation (without wheeling) with the costs during the wheeling operation.

2.4.4 Changes in Spinning Reserves or Unloadable Generation

In some instances of wheeling, it may be necessary to increase the level of spinning reserves on the wheeling system to account

for the potential loss of the power imported for wheeling. If the wheeling import is unexpectedly lost, the utility to which the power is being wheeled will still be present as a load on the wheeling system. While most wheeling agreements would allow the wheeling utility to immediately halt exports to the receiving system, the necessary control actions require a finite amount of time, and additional spinning reserves may be necessary to maintain the wheeling system's stability during that time. The cost of any needed additional reserve is a potential cost of wheeling.

The need for additional reserves can be determined using the wheeling utility's spinning reserve criteria. If a single contingency criteria is used (spinning reserve is available to offset the loss of the largest power flow into the system - the largest operating generator or power import), then additional spinning reserve will be needed if the power imported for wheeling becomes the largest single contingency on the system. Similarly, for any other reserve criteria, the level of spinning reserve will need to be increased only if the power imported for wheeling affects the formula used for determining reserve.

In contrast to the need for additional reserves, the amount of unloadable generation present on the wheeling operation. Unloadable generation is that amount of generation and imports which could be quickly removed from a system without resorting to emergency shutdown of a generating unit. If the export of wheeling power is suddenly stopped, there will be an excess of power entering the wheeling system, so the unloadable generation must be sufficient to compensate for such a loss. Again, the level of unloadable generation present on a system will need to be increased only if the amount of power exported for wheeling affects the formula used for determining unloadable generation. For example, if the wheeling export becomes the largest system "load," then unloadable generation would probably have to be increased.

2.4.5 Effect on System Stability

The altered loading of the wheeling system may have other adverse effects on the transient or dynamic stability of the system. If this occurs, steps must be taken to restore the system to a stable condition if the wheeling operation is to take place. Changes should be made to generator or line loadings, and if such changes are not sufficient, additional facilities will be required for the wheeling operation. The question of additional facilities is addressed in Section 5.1 of this chapter.

2.4.6 Conclusion

For a proposed wheeling operation, the effects described in this section should be analyzed with two objectives:

1. To determine if the wheeling operation will affect the wheeling system to a degree that will make the operation unfeasible.

2. If the operation is feasible, to determine the costs incurred by the wheeling utility as a result of the wheeling operation.

These analyses are discussed in the next two sections of this chapter.

2.5 Feasibility of a Wheeling Operation

The possible effects of a wheeling operation on the wheeling utility were described in the previous section. For a proposed wheeling operation, these effects must be analyzed in order to evaluate the feasibility of the operation before it is carried out. The answer to the following question will determine the feasibility of a proposed wheeling operation:

During the wheeling operation, is an adequate level of reliability maintained on the systems providing the wheeling service?

2.5.1 Criteria for Determining Feasibility

There are several ways to evaluate the reliability of a system, but the majority of U.S. utilities presently use deterministic criteria in assessing transmission system reliability.[8] An example of such criteria is presented in the National Electric Reliability Council report Transfer Capability: A Reference Document.[9] A First Contingency Incremental Transfer Capability is defined as: "The amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions:

1. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The bulk power system is capable of absorbing the dynamic power swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer.

3. After the dynamic power swings following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer, but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

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8. The National Electric Reliability Study: Final Report, U.S. Department of Energy, DOE/EP-0004, April 1981.

9. Transfer Capability, A Reference Document, National Electric Reliability Council, 1980.

For a utility using this criteria, the system must meet the three conditions during all operations, including wheeling. Some systems use a more stringent criteria, such as second contingency incremental transfer capability, in which the system must be able to withstand any two simultaneous contingencies. Whatever criteria are used in normal operations also apply to wheeling operations.

If a system does not meet the necessary reliability criteria during a wheeling operation, changes should be made in system generator and line loadings in an attempt to meet the criteria. If these changes are not sufficient, then additional facilities will be required for the wheeling operation.

2.5.2 Additional System Facilities for Wheeling

If it is necessary to add facilities to a system to make a wheeling operation feasible, the cost of those facilities is an additional cost for wheeling. However, because the new facilities may provide other benefits beyond just making the wheeling operation feasible, a problem may arise in determining whether the entire cost of the new facilities, or only part of that cost, should be considered a cost of wheeling. It will not be attempted in this discussion to present a method of assigning costs, but an important point concerning such cost assignment will be made.

The main benefit of the new capacity, beyond allowing wheeling to take place, will probably be an increase in overall reliability of the wheeling system. There are cases, however, in which a utility has no need for additional reliability, and thus cannot justify any expenditure for that purpose. If this is the case, then the benefit of increased reliability cannot be considered in assigning the costs of the new facilities. If the new facilities do not provide any needed benefits beyond wheeling, then the entire cost of the new facilities is a result of the wheeling transaction.

2.5.3 Conclusion

The criteria presented in this seciton should be used to evaluate the feasibility of a proposed wheeling operation before it is carried out. If the operation is judged to be feasible, then the next analysis should address the costs incurred by the wheeling utilities as a result of the wheeling operation.

2.6 Demonstrating the Effects and Costs of Wheeling Services

2.6.1 Analysis Technique

The effects of wheeling and feasibility criteria have been discussed, and now the question of what should be done to demonstrate feasibility and costs of wheeling will be addressed. The following is a very general analysis technique which would be applicable to most wheeling operations:

1. From hourly load forecasts for the wheeling system during the period the wheeling operation is to occur, determine an optimal generating unit commitment schedule for the system as it would be without the proposed wheeling operation.

2. Similarly, determine the optimal unit commitment schedule for the system as it would be with the wheeling operation.

3. Using typical load data for the system, simulate both cases for the wheeling period:

   - Compute optimal economic dispatch.

   - Using load flow, transient stability, and dynamic stability studies as needed, and the wheeling utility's reliability criteria, evaluate the

feasibility of the proposed wheeling operation. If the operation is not feasible, make changes in generation and system controls and return to Step 1. If the operation is feasible, proceed to Step 4.

4. By comparing load flow, unit commitment, and economic dispatch data from the two cases, determine which parts and components of the system are affected by the wheeling operation.

5. Using the utility's production costing techniques, estimate production costs for the two cases. The difference in production costs between the two cases are the incremental costs (or benefits) of wheeling to the wheeling utility.

The load flow and stability studies referred to in the outline are expensive to use, so the general analysis technique may not be justified or needed in every case:

- Small economy transactons will often not be significant enough to overload any components or cause stability problems.

- For certain system configurations, stability limits for line and component loadings can be estimated.

- If costs have been determined for one wheeling transaction, minor changes in the operation may not affect the costs. For changes in the amount of power wheeled, certain costs might be considered proportional, within certain limits, to the amount of power wheeled.

It is very important to remember, however, that if there is a disagreement among those involved concerning effects or costs of a wheeling operation, simulation studies may be needed to settle the disagreement. In order to determine any valid rules, though, the effects each of these factors has on a wheeling operation need to be studied through computer modeling and other analysis techniques.

An important factor to consider in any analysis is the experience a utility has had in operating its system. Utility engineers often have a good idea what their system will do under certain circumstances. However, in a dispute over a wheeling operation, this type of judgment based on experience should be supported by quantitative evidence such as operating records and load flow and stability simulation data.

There are many other technical considerations in a wheeling operation, some of which will now be discussed. All of these need further study before they can be incorporated into general rules.

2.6.2 Effects on Other Systems

Power systems which are not directly involved in a wheeling operation may still affect or be affected by it. Consider, for example, the arrangement shown in the Fig. 2.6.1.

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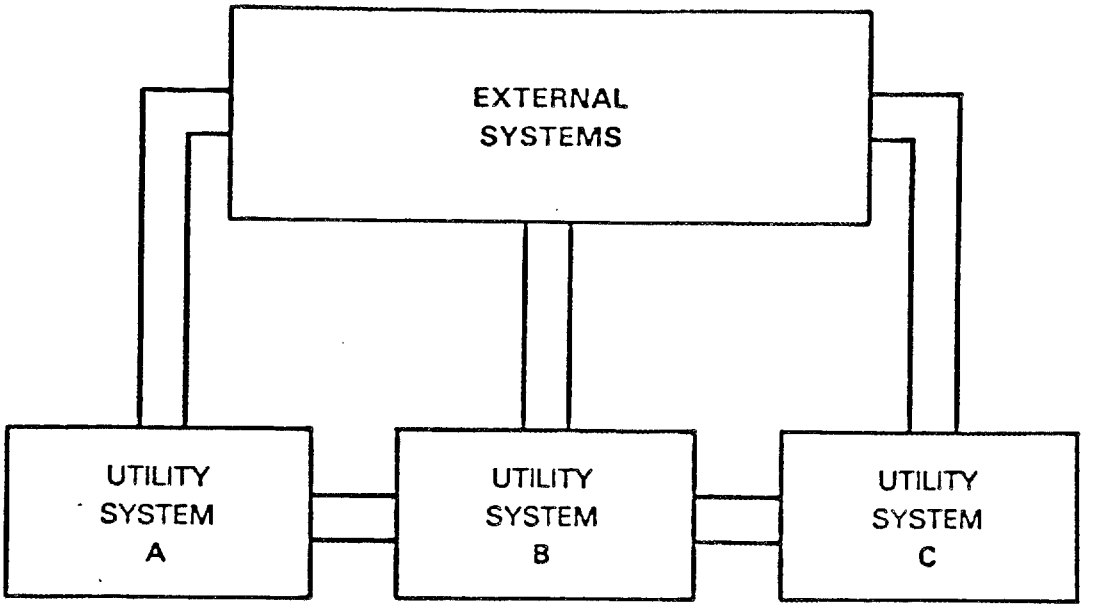

Fig. 2.6.1. Example - Effects of Wheeling on Other Power Systems

System B has agreed to wheel power from A to C. The external systems shown provide a parallel path from A to C, and part of the power to be wheeled may follow this path. While an attempt will be made to limit the amount of power flowing through the external systems, the flows may still be significant enough to cause conditions on these systems to limit the amount of power that can be wheeled. The external systems may experience any of the potential effects of a wheeling operation. It is therefore important to include the external systems in simulations of the wheeling operation. Instead of using full models for these systems, though, a less detailed equivalent model can be used to represent the external systems. If the necessity is then indicated by significant power flows across system borders in the initial simulations, the external systems can be analyzed in more detail.

2.6.3 Wheeling vs. Two-Party Transaction

It is possible to compare a potential wheeling operation with a conventional exchange in which the wheeling utility simply generates and sells power rather than wheeling it. Any of the effects described for wheeling can also occur during conventional exchanges and the same techniques of cost analysis apply. Analyze three alternatives:

- No exchange
- Conventional exchange
- Wheeling

A comparison from the wheeling utility's standpoint can then be made by comparing the effects and costs of each alternative.

2.6.4 Voltage, Location and Number of Delivery Points

The best voltage level, location, and number of delivery points will also be a consideration in some wheeling transactions. Unless additional facilities for wheeling are being considered, the number of alternatives will be limited by the installed equipment on each system, the configuration of system interconnections, and the difficulty of controlling power flows on an ac system. The possible alternatives, including adding new facilities, can be compared using the feasibility and production cost criteria. Besides considerations of system configuration, the only other relationship between delivery voltage and the amount of power wheeled is the usual relationship in any power delivery arrangement that line losses decrease as delivery voltage increases.

2.6.5 Advance Notice

It is important that a wheeling utility be given sufficient advance notice of a new wheeling transaction or changes in an existing one. For a proposed new transaction, the utility should be given time to perform studies as needed to determine the feasibility, effects, and costs of the transaction. The amount of advance notice given for changes in an existing agreement depends on the applicability of previous studies to the changes. If the feasibility and costs of the new arrangement are known, the utility only needs time to determine the proper system control adjustments. If not, sufficient time should be allowed for assessing the feasibility and costs.

For operational changes in wheeling transfers, i.e., changes in power levels, starting and ending times, etc., different utilities will have different requirements. Certain systems are capable, for example, of making a more rapid transition between power levels than others, and some systems will encounter more severe effects from such a change. The importance of advance notice also depends on the magnitude of the transaction and the magnitude of the proposed change.

2.6.6 Conclusion

The analysis techniques described in this section can be applied to a proposed wheeling operation to evaluate the feasibility and potential costs of the operation. The feasibility criteria, developed in Sect. 5.1 of this chapter, are based on common electric utility reliability requirements, and cost estimates are made using utility production costing analyses. The techniques are general techniques applicable to any proposed wheeling operation.

2.7 Conclusions

Four topics have been addressed in this chapter:

- The structure, operation, and functions of an electric utility system (Section 2)

- A definition of wheeling (Section 3)

- The possible technical effects of wheeling on the wheeling system (Section 4)

- A method for analyzing and quantifying the effects and their resulting costs (Sections 5 and 6)

Discussions of these four topics form a general technical reference regarding wheeling operations.

There seems to be a general feeling in the electric utility industry that the term "wheeling" signifies an operation which has the purpose of transferring electric power using the facilities of a utility which did not generate or does not intend to use the electricity. From this, the definition of wheeling of this report was formed:

> An operation will be classified as wheeling if it involves two or more separate electric utilities, and power system facilities of at least one of the utilities are used to transfer electric power that was not generated by and is not intended for final use by the utility or an end-use customer of that utility.

The definition is intended to include a broad range of operations, including:

- "Flow-through" wheeling in which the power to be transferred flows through the delivery system of the wheeling utility,

- "Displacement" wheeling in which the power to be wheeled displaces generation or power imports near the point at which it enters the wheeling system,

- Any combination of flow-through and displacement wheeling.

All of these were included in the definition because they all serve the same basic purpose, that is, to transfer power using facilities owned by a utility other than that which generated the power and that which uses the power or sells it to an end-use customer. Wheeling includes only those transactions in which the power to be wheeled is simultaneously imported and exported by the wheeling utility.

A wheeling operation cannot be analyzed as an isolated occurrence on the wheeling system. Instead, the operation represents a new set of system conditions which must be analyzed from an overall system standpoint. Both generation and the power delivery system including distribution, subtransmission, and transmission systems, can be affected by wheeling. Possible effects include:

- Altered delivery system loading--can affect power losses and stability of the system

- Changes in optimal unit commitment and economic dispatch

- Changes in required reserve and unloadable generation levels.

Any of these potential effects can result in costs or benefits to the wheeling utility. However, these costs or benefits are not necessarily related to the amount of power wheeled. Operating costs due to wheeling can be estimated by using the utility's production costing techniques to compare various wheeling and non-wheeling alternatives. The difference between production case are the operating costs of wheeling for that particular operation.

The feasibility of a specific wheeling operation should be determined based on the wheeling utility's usual reliability and operating criteria. This usually includes maintaining system voltages within specified limits and maintaining system stability at all times. Load flow and transient and dynamic stability studies, as well as the utility's operating experience, will all be useful in assessing the feasibility of a wheeling transfer.

Detailed simulation studies may not be justified or necessary for every wheeling transfer. Sometimes one study or set of studies may apply to several situations. However, no specific rules have yet been developed for determining when simulations are needed.

It is important to remember that the analysis technique presented in this report is system-specific. Further research is needed concerning the technical considerations covered in this report. Through computer modeling and other analysis techniques it might be possible to develop a generic method of analyzing wheeling operations. However, until such a method is developed, wheeling operations in which questions about feasibility or costs arise should be evaluated on a case-by-case basis using the various system studies, and most importantly, sound engineering judgment, to estimate the effects and costs of each individual wheeling operation.

2.8 Appendix - Basic Concepts of Electric Power

2.8.1 Alternating and Direct Current

A basic classification of electrical circuits refers to the way in which current flows in the circuit. Two common possibilities are direct current (dc) and alternating current (ac). Direct current flows at a constant rate in one direction through the circuit, yielding a constant value of current over time (Figure 2.8.1). The instantaneous magnitude of alternating current follows an oscillating (sinusoidal) pattern (Figure 2.8.2).

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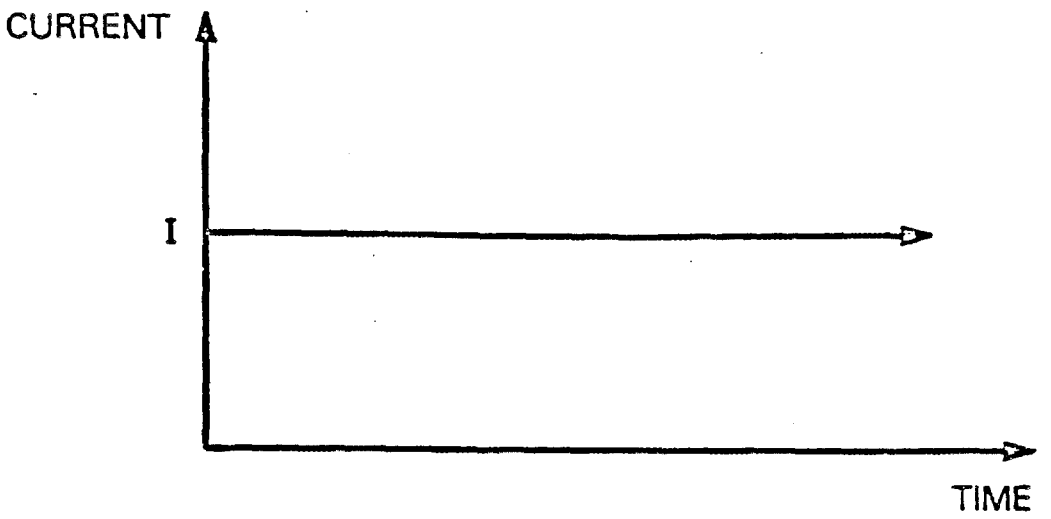

Fig. 2.8.1. Direct Current

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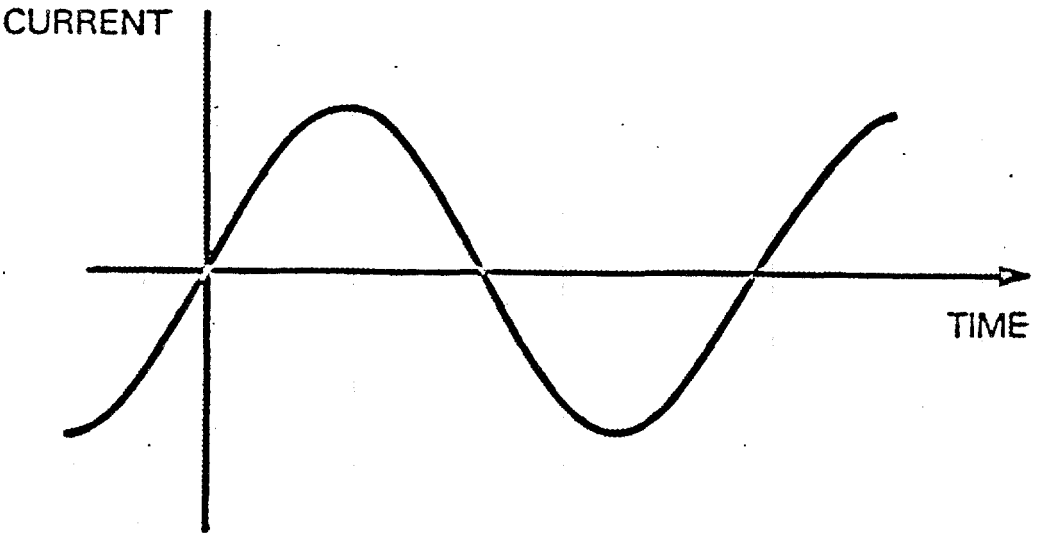

Fig. 2.8.2. Alternating (Sinusoidal) Current

(For further discussion, see Ref. 8, pp. 11-19.)

2.8.2 Sinusoidal Functions

The period of a sinusoidal function, shown as T in Figure 2.8.3, is the amount of time required for the function to make one full positive/negative cycle. The frequency of the sinusoid, measured in hertz, is the number of such cycles occurring in one second. Frequency is the mathematical inverse of period. In U.S. power systems, frequency is 60 Hz. In Figure 2.8.3, the value of the sinusoidal function represents the magnitude of a quantity (e.g., voltage, current, or power) at a certain time for a specified point on the system.

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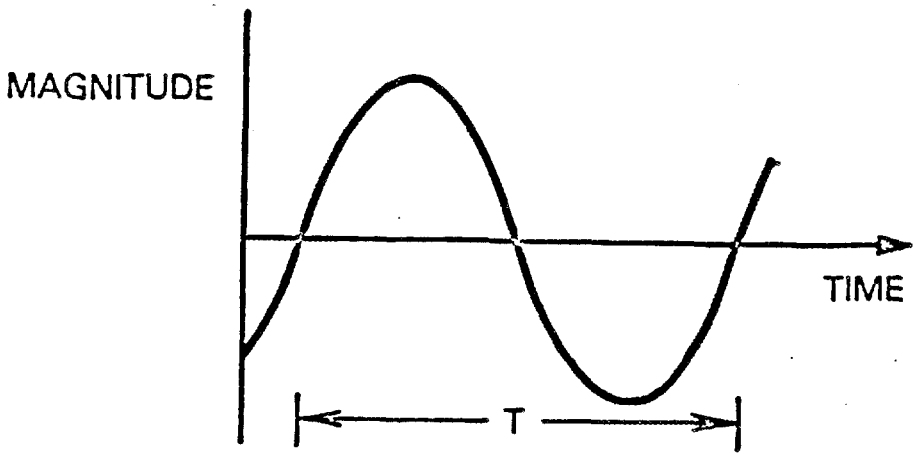

Fig. 2.8.3. Sinusoidal Function

In Figure 2.8.4, functions a and b are sinusoids with the same frequency. The difference, in degrees, between the points at which each crosses the zero axis is the phase angle, 0, between the two sinusoids. The two are said to be out of phase by 0 degrees, and in this case, a is leading b by 0 degrees. If 0 is zero, the sinusoids are in phase.

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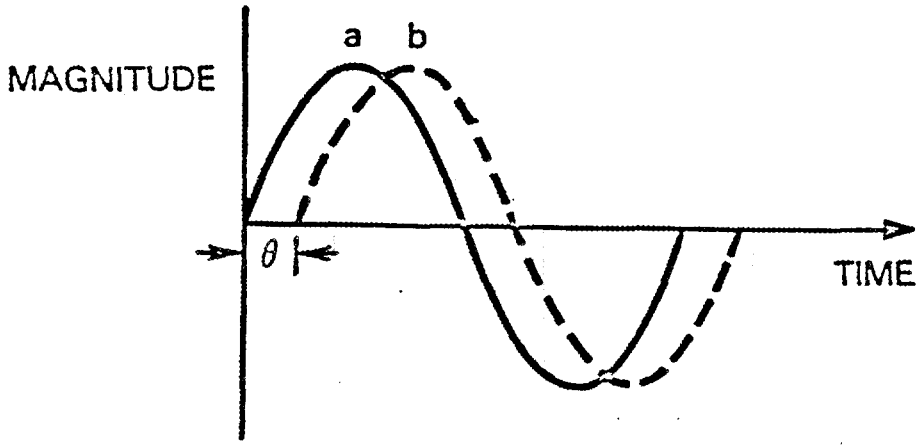

Fig. 2.8.4. Sinusoids Out-of-Phase

(For further discussion, see Reference 8, pp. 265-270.)

2.8.3 Ac Systems

To generate current at a frequency of 60 Hz, a simple two-pole generator would spin at a rate of 3600 revolutions per minute, or 60 revolutions per second. Therefore, for each complete revolution of the generator rotor, one complete cycle of current is produced. As the rotor turns 360 degrees (one revolution), the current can also be considered to move through 360 degrees, as illustrated in Figure 2.8.5.

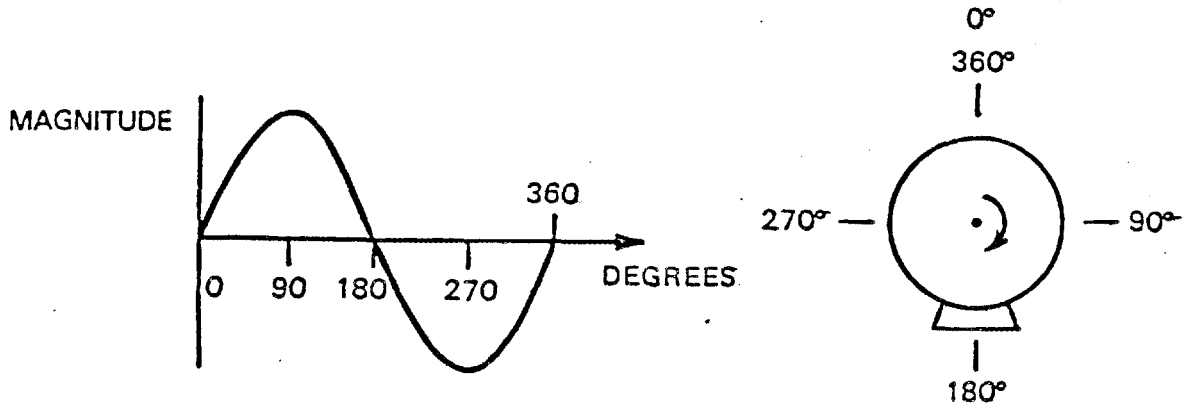

Fig. 2.8.5. Phase of Alternating Current

When an ac system is in steady-state operation, i.e., no changes are being made to the system, the frequency of the current must be constant and the phase angles between voltages and currents non-varying throughout the system. This is known as synchronous operation. In reality, a large power system is never in true steady-state operation due to constant variations in loads on the system. So in a practical sense, synchronous operation means the system is operated to provide an average frequency of 60 Hz throughout the system, with phase angles remaining within certain limits. A system is said to be stable if it is always moving toward a state of constant 60 Hz frequency and non-varying phase angles. If synchronous conditions on a system are not met, the result can be partial or total system failure.

An illustration of phase angle difference in an electric power system is given in Figure 2.8.6. Generators A and B are located at different points in the same utility system. Both are generating power at the same frequency. However, the point at which the instantaneous value of the current from generator A, represented by sinusoid a, reaches zero is different from the

point at which the current from B, represented by sinusoid b, is zero. The difference between these two zero points, measured in degrees, is the phase angle between the currents in generators A and B.

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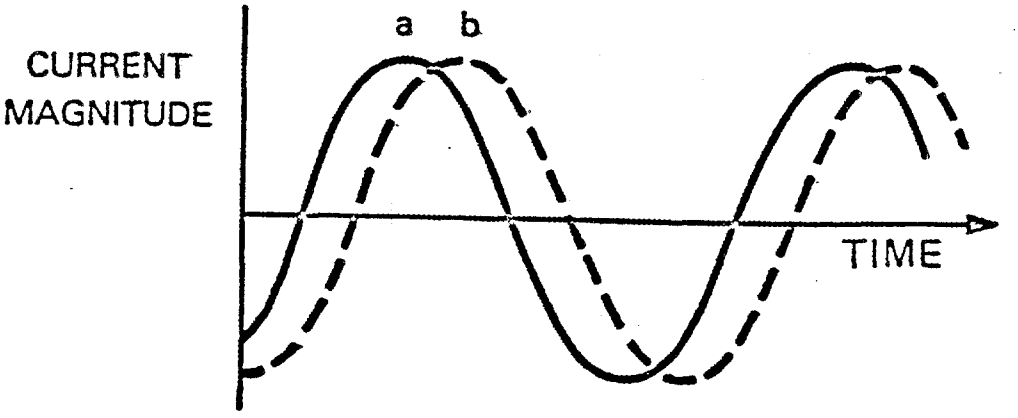

Fig. 2.8.6. Currents Out-of-Phase

This discussion could also apply to the phase angle between voltages at generators A and B.

Another possible difference in phase can be demonstrated using Figure 2.8.7. Let "a" be the voltage at one point in the system, "b" be the current at the same point. The voltage and current are out of phase by 0 degrees at that point.

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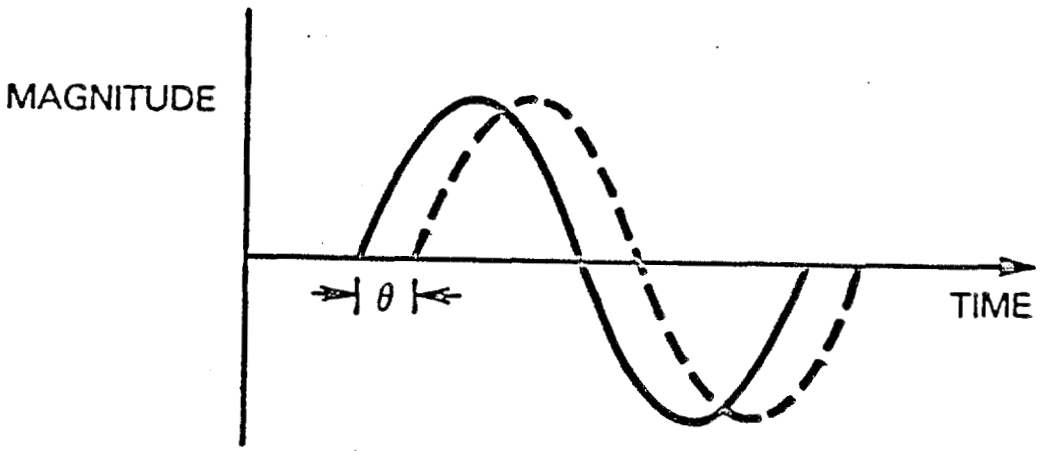

Fig. 2.8.7. Voltages Out-of-Phase

Variations in the phase angles of voltages and currents in a system are caused by the inductance and capacitance of system elements. With proper control settings, the voltage and current at a generator output can be in phase, but as the power flows through the system, inductive and capacitive characteristics create time delays in the voltages and current, causing them to become out of phase. Inductance and capacitance have no effect on a steady state dc system, because current and voltage are not time-varying. Therefore, all quantities in a pure dc system are in phase (phase angles are all zero). Phase differences do occur, however, in ac systems, and are quite significant. The important phase differences are:

1. Phase angle between voltages at different points in the system.

2. Phase angle between voltage and current at a specified point.

(Additional reference: Reference 8, Chapter 8.)

2.8.4 Electric Power

If a mathematical analysis of steady-state power flow on an ac system is performed, it can be shown that if the phase angle between the voltage and current is not zero, energy is returned from the power system to the generator during part of each ac cycle. This is due to energy being alternately stored in and released from inductance and capacitance throughout the power system. When an element (any part of an electrical circuit) is purely resistive, voltage and current are directly related in the element, so voltage follows current (current follows voltage) exactly. In an inductive element, however, the inductance delays the current waveform, and thus the voltage leads the current in time. Similarly, capacitance delays the voltage waveform, so current leads voltage in a capacitor.

In a steady-state dc system, inductance and capacitance have no effect, so voltage and current are always in phase, that is, the peak value of voltage occurs at exactly the same time as the peak value of current. In an ac circuit, because of the energy storage in inductive and capacitive elements, the current and voltage are not in phase, meaning there is a time delay between their peak values. During certain portions of the ac cycle, one of the values can be negative while the other is positive. Since instantaneous electric power is the product of voltage and current, this results in a negative (reverse) power flow. This reverse flow performs no useful work, increases energy losses in the system, and in effect sends back a portion of the useful power received from the generator.

The total power can be mathematically represented as a combination of two quantities:

- Real power, whose value is never negative, that is, it always flows through the system from generator to load, and,

- Reactive power, the component of power which flows continuously back and forth between the generator and the rest of the system.

It is desirable to reduce reactive power transmitted in a system as much as possible, since it produces unnecessary and useless loading of transmission lines and generators. However, it can never be completely eliminated.

Single-phase power is power which can be delivered using one energized conductor and one return conductor. Single-phase refers to the fact that there is only one value of voltage and current at the generator terminals. Power delivered by a single-phase circuit pulsates around an average value at a frequency of twice the ac frequency, as shown in Figure 2.8.8, where the sinusoid represents instantaneous power flow.

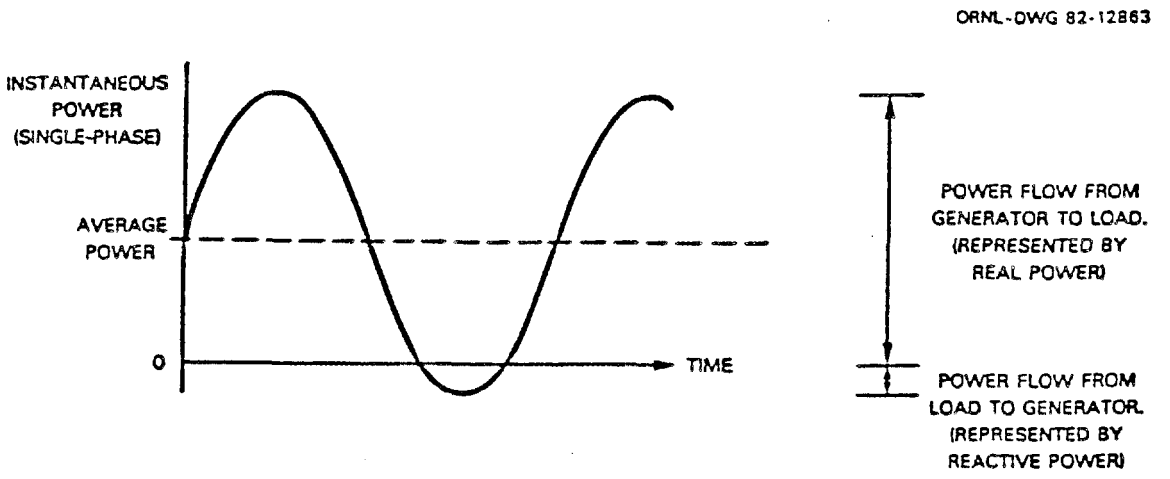

Fig. 2.8.8. Single-Phase Power

In a three-phase system, there are three energized conductors and one return conductor, which is usually the earth. Large power systems are three phase because of economic advantages over other arrangements. In a balanced three-phase system, i.e., one in which the loads connected to each phase are equal, the voltage magnitudes on all three lines are equal, but each voltage is 120 degrees out-of-phase with the other two. This is depicted in Figure 2.8.9. Likewise, the currents are equal in magnitude, but are 120 degrees out-of-phase. An important

characteristic of three-phase power can be observed by summing the three currents, A, B, and C of Figure 2.8.9. The result is that the instantaneous sum of the currents is zero at all times. This means that for perfectly balanced loads, there is no return current present. In reality, the loads are never perfectly matched, so a small return current is always present, but it is much smaller than it would be on an equivalent single-phase system. The power in each phase oscillates about an average value as in Figure 2.8.8, but when the three different values of power are summed, the total power output of the three-phase system is constant. This contributes to smoother and more efficient operation of generators and motors, because the torque on the rotating shaft is constant.

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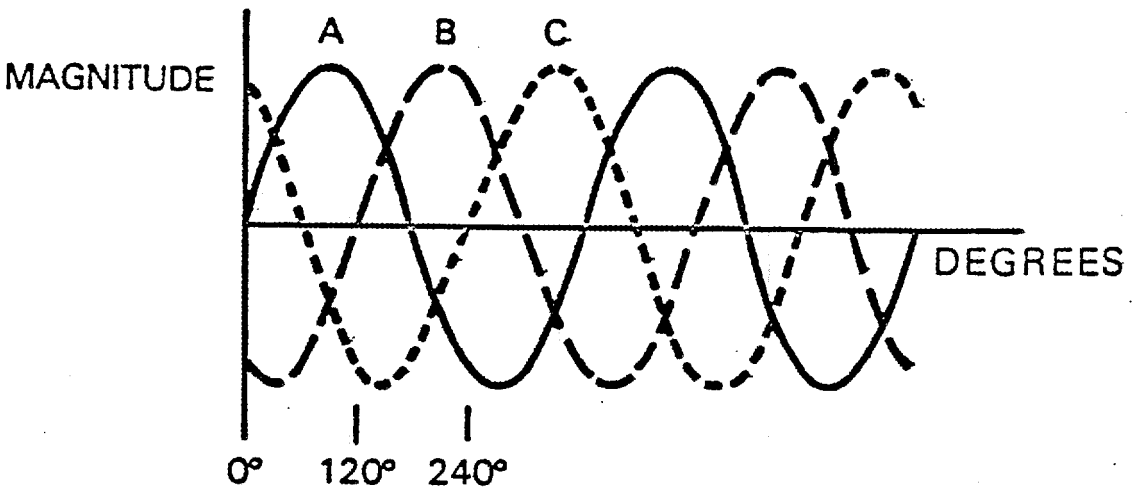

Fig. 2.8.9. Three-Phase Power

Figure 2.8.10 depicts a simple three phase system. Loads A, B, and C are equal, so the return lines from each are simply connected together, and no return conductor to the generator is needed.

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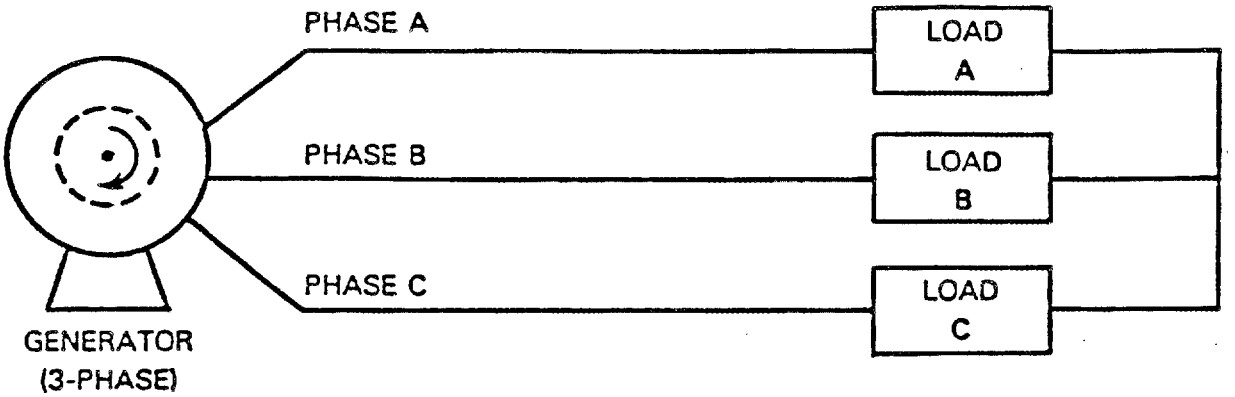

Fig. 2.8.10. Three-Phase System

(Additional reference: Reference 7, pp. 21-34.)

2.8.5 Ac Power Flow

2.8.5.1 Concept

The idea that power "flows" through an electrical delivery system is an idea that is very complex to strictly define. However, a conceptual understanding of this idea is not difficult to achieve, and since "power flows" are dealt with often in this report, such an understanding is important.

The system shown in Fig. 2.8.11 will be used to demonstrate the concept of power flow. This system is a simple hydraulic lift, such as would be found in an automobile service garage. This system will be used to demonstrate the concept of power flow. Power in this system flows from the electrical power source on the left to the hydraulic lift on the right.

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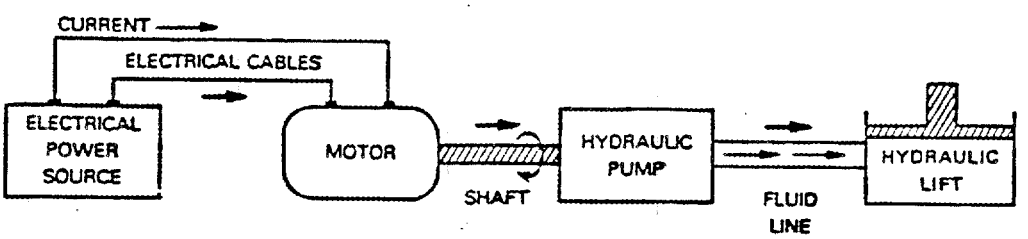

Fig. 2.8.11. Hydraulic Lift System

The power flowing in this system flows along several different delivery paths. The first path is from the electrical power source to the electric motor. The power thus flows over the electrical cables, similar to power flow in an electric utility system. From the motor, the power is transferred to the hydraulic pump, and this transfer is made over the rotating shaft that connects the two. Finally, the power is delivered to the hydraulic lift, and this time the power flows through the fluid line between the pump and the lift.

Thus, while no physical "power unit" can be seen to move from the electrical source to the hydraulic lift, it is still conceptually accurate to say that power is transferred through this system. It is this concept that is used in the study of an electrical delivery system to describe the delivery of power to the various system loads. This concept greatly simplifies the analysis of electric utility systems.

2.8.5.2 Mathematical Analysis

Consider a single ac transmission line with the following characteristics:

- Vs is the magnitude of the voltage at the end from which power is sent.

- Vr is the magnitude of the voltage at the end where power is received.

- δ is the phase angle between the sending and receiving end voltages using receiving end as reference.

- The phase angle of the voltage at the receiving end is zero.

- The value X for a specific line is a constant which represents the equivalent impedance of the line at frequency of 60 Hz.

For this elementary representation of a transmission line, a simple but informative equation for the real power flow on the line can be written:[10]

$$P = \frac{V_s V_r}{X} \sin \delta$$

By examining the real power equation, it is seen that there are three variables which may be adjusted to control the flow of real power on the line:

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10. F. W. Sears, M. W. Zemansky, and H. D. Young, University Physics, Part II, Addison-Wesley, Reading, Massachusetts, 1976.

- Vs, the sending end voltage magnitude.

- Vr, the receiving end voltage magnitude.

- δ, the phase angle between sending and receiving end voltages.

To vary the voltage magnitudes Vs and Vr, capacitors may be switched on and off the system, and voltage regulating transformers may be used. The phase angle may be adjusted through the use of phase shifting transformers, although this is not generally used as a means of power flow control.

For the special case of power flow from a generator, define the variables:

- Vg is the internal generator voltage magnitude.

- Vt is the voltage magnitude at the external terminals of the generator.

- δ is the phase angle between the internal and external generator voltages, with the external terminal voltage as reference.

- X is again an impedance constant for a given generator.

The equation for real power is now:

$$P = \frac{V_g V_t}{X} \sin \delta$$

and the real power flow is affected by varying Vg, Vt, or δ. Increasing the power input to the generator (e.g., adding more coal to the boiler) will increase the phase angle and thus increase real power flow out of the generator. There are

controls, called excitation controls, on an ac generator which adjust the values of Vg and δ, but these are mainly used to control reactive power flow. Another simple equation may be used to demonstrate control of reactive power flows:[11]

$$Q = \frac{V_r}{X} (V_s \cos \delta - V_r)$$

Varying the voltages Vr and Vs will change the reactive power flows on the line. Reactive power from a generator is controlled by using the excitation controls to vary internal generator voltage Vg and phase angle δ. For further discussion, see Reference (6), Chapter 9.

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11. W. D. Stevenson, Elements of Power System Analysis, McGraw-Hill, New York, 1975.

2.9 Glossary

Admittance indicates the ease with which alternating current flows in a circuit. Admittance is the mathematical reciprocal of impedance. Shunt admittance is the admittance between a power line and ground. See Ref. 8, pp. 300-301.

Capacitance refers to the ability of an element to resist sudden changes in the voltage across the element. Capacitance relates to the storage of energy in an electric field. The capacitance of a transmission line arises from the electric field among conductors and the earth. See Ref. 8, pp. 147-152.

Technically, any element which carries electrical current is a conductor. For the purposes of this report, however, the term "conductor" will refer to the current-carrying electrical cables of the power system.

The movement of electrical charge is known as current. The numerical value of current indicates the rate at which charge is flowing. See Ref. 8, pp. 11-20.

An electric field exists in a power system between any two conducting circuit elements which are at different voltage levels. See Ref. 9, Ch. 25.

The impedance of a power system conductor is a combined value used to represent inductance and resistance of the conductor. Impedance, which is usually assumed to be constant at a specific frequency, indicates the ability of the conductor to impede the ac current flow at that frequency. See Ref. 8, pp. 296-299.

Inductance indicates the ability of an element to resist sudden changes in the flow of current through it. Inductance relates to the energy storage in the magnetic field surrounding the element. See Ref. 8, pp. 136-140.

A magnetic field exists in a power system around any element through which electric current is flowing. See Ref. 9, Ch. 30.

Resistance indicates the ability of a circuit element to resist the flow of current. See Ref. 8, pp. 31-33.

Voltage refers to the work required to move electrical charge (cause current to flow) between two points. See Ref. 8, pp. 16-19.

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Chapter 3

Economic Aspects of Wheeling

3.1 Introduction

3.1.1 Overview

This chapter contains a theoretical economic analysis of the costs of providing wheeling services and how these costs can be reflected in wheeling rates. The cost structure of providing power transmission services, including wheeling, is reviewed, and it is shown that such services are usually provided at continuously decreasing average cost. The theoretical economic behavior of a natural monopoly is then examined under various institutional structures. The analysis then focuses on the economic costs of wheeling.

Because wheeling transactions are regulated, potential impacts of regulatory goals on the level of wheeling rates are examined. Recommendations are made concerning how conflicts among regulatory goals can be reconciled and implemented in wheeling rate design.

3.1.2 Background

As stated in Chapter 2, wheeling is the simultaneous transfer through transmission facilities owned by a utility of electrical power that was not generated by and is not intended for final use or final sale to an end-use customer of that utility. For example, if Utility B uses its transmission facilities to transfer electric power sold by Utility A to Utility C, Utility B is said to wheel power from Utility A to Utility C. This type of transaction will be called a third-party wheeling

arrangement. Similarly, if Utility A owns or has an entitlement in an isolated generating facility that is not directly interconnected with its transmission grid but is interconnected with Utility B's grid, Utility A may contract with Utility B to wheel power from the isolated generating facility to Utility A's grid. This type of transaction, will be referred to as second-party wheeling.

Typically, wheeling transactions require bilateral contracts between or multilateral contracts among the utilities participating in the transactions. Third-party wheeling transactions can be completed under two or more bilateral contracts between the participating utilities (e.g., bilateral bulk power contracts between Utilities A and C and bilateral wheeling contracts between Utilities B and C in the example above) or a multilateral agreement among participating utilities (e.g., a multilateral agreement among Utilities A, B, and C). Bilateral contracts are necessary in second-party wheeling transactions.[1]

A wheeling arrangement, regardless of whether it is a bilateral or multilateral agreement, may specify the points at which the wheeling utility receives and delivers the power, a rate schedule or formula that determines the compensation received by the wheeling utility, various other terms and conditions under which the power is wheeled, and whether the arrangement may be amended or terminated. If wheeling arrangements involve the transmission of electric power pursuant to the Federal Power Act, the Federal Energy Regulatory Commission (FERC) has regulatory responsibility for reviewing and approving or rejecting wheeling arrangements filed by electric utilities.

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1. A wheeling transaction may be comprised of a series of second- and third-party transactions. For example, to receive its entitlement from a generating unit located in Utility A's service area, Utility D might have to engage in a second-party transaction with Utility A and third-party transactions with Utilities B and C if the latter utilities provide a transmission interconnection between Utilities A and D.

3.2 General Cost Characteristics of Power Transmission

A natural monopoly occurs when there is a "tendency to decreasing unit costs over the entire extent of the market."[2] That is, all firms serving the market face continuously decreasing long-run average costs, i.e., increasing returns to scale in production. Under this condition, a single firm can serve the entire market at less cost than two or more firms.[3]

The provision of transmission services, such as wheeling, is an example of a natural monopoly. Specifically, increasing returns to scale are achieved as the capacity of a transmission line, expressed in megawatts (mW), or gigawatts (gW), is increased. That is, the cost per mW of capacity decreases as the capacity of a transmission line is increased. For example, the total cost of a 2,700 mW, 800 kilovolt (kV) line that is 200 miles long may be as high as $152 million (expressed in 1985 dollars),[4] which represents an average cost per mW of approximately $56,300. However, as shown in Figure 1, this average cost is only about 60 percent of the average cost per mW of a 1,100 mW, 550 kV line and only about 25 percent of the average cost per mW of a 310 mW, 463 kV line.

Once a transmission line with a given capacity has been built, the average cost of transmitting each mW over that line generally decreases with increases in mW transmitted up to the

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2. Kahn, 1971. Vol. 2, p. 119.

3. Because only one firm serves the entire market in a natural monopoly, the capital investment requirements facing the firm are typically high. Two other characteristics of natural monopolies are the production of nonstorable goods or services and product demands that vary by time and market location. See Kahn, 1971, Vol. 2, pp. 119-120.

4. Commonwealth Association, Inc., 1978.

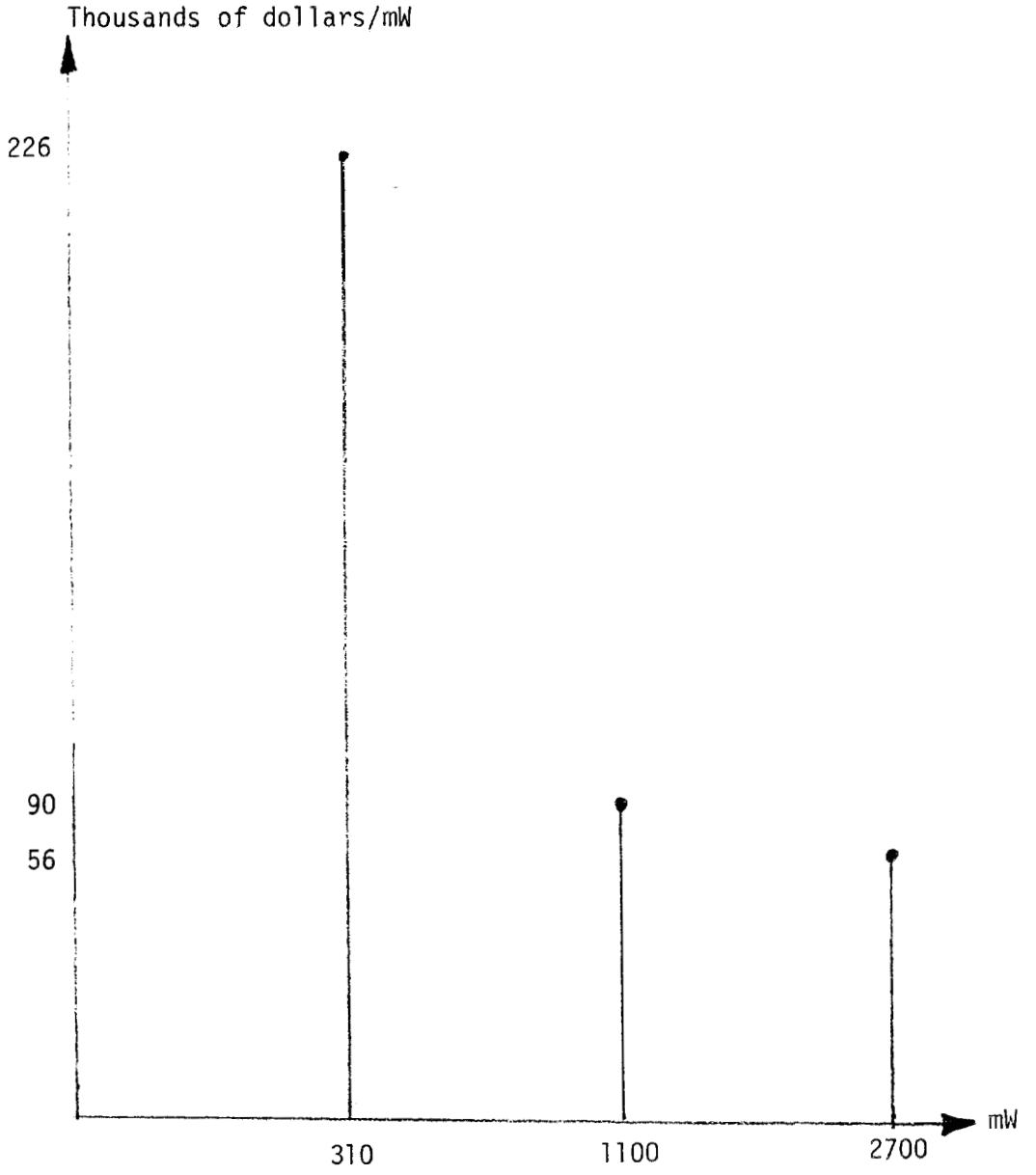

Fig. 1. Decrease in costs with increase in mW transmitted.

line's capacity limit. Because a large portion of a line's total operating costs (i.e., fixed plus variable costs) are fixed, average total costs decrease as fixed costs are spread over a greater number of transmitted mW.[5] It should be noted that the decreasing average total cost characteristic of an existing transmission line does not say anything about the existence of increasing returns to scale across all output levels. It is the planning concept of long-run decreasing average costs across all output levels that indicates the potential for natural monopoly.

The economies of scale present in transmission service are depicted in Figure 2. The curve LRAC identifies the minimum long-run average total cost of transmitting varying levels of mW's. The curve LRMC represents the long-run marginal cost of transmitting each additional mW. Because LRAC decreases continuously, LRMC is less than LRAC at all levels of transmitted mW. That is, the transmission of each additional mW decreases the LRAC of all mW transmitted.

3.3 General Behavior Characteristics of Natural Monopoly Utilities

Microeconomic theory provides some useful insights into the rational economic behavior of a utility transmitting power at decreasing average costs with respect to the prices it charges and the quantities of power that it transmits at each price. In general, any firm that operates as a natural monopoly must charge a price greater than its marginal cost of production to cover its total costs, including a reasonable return on investment. However, deviations from the general axiom of setting price at marginal production costs result in a set of

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5. This assumes that the rate of increase in variable transmission costs is less than the rate of decrease in average fixed costs with increases in transmitted mW. Generally, the capacity of a line is determined by stability problems and occurs before variable transmission costs increase rapidly.

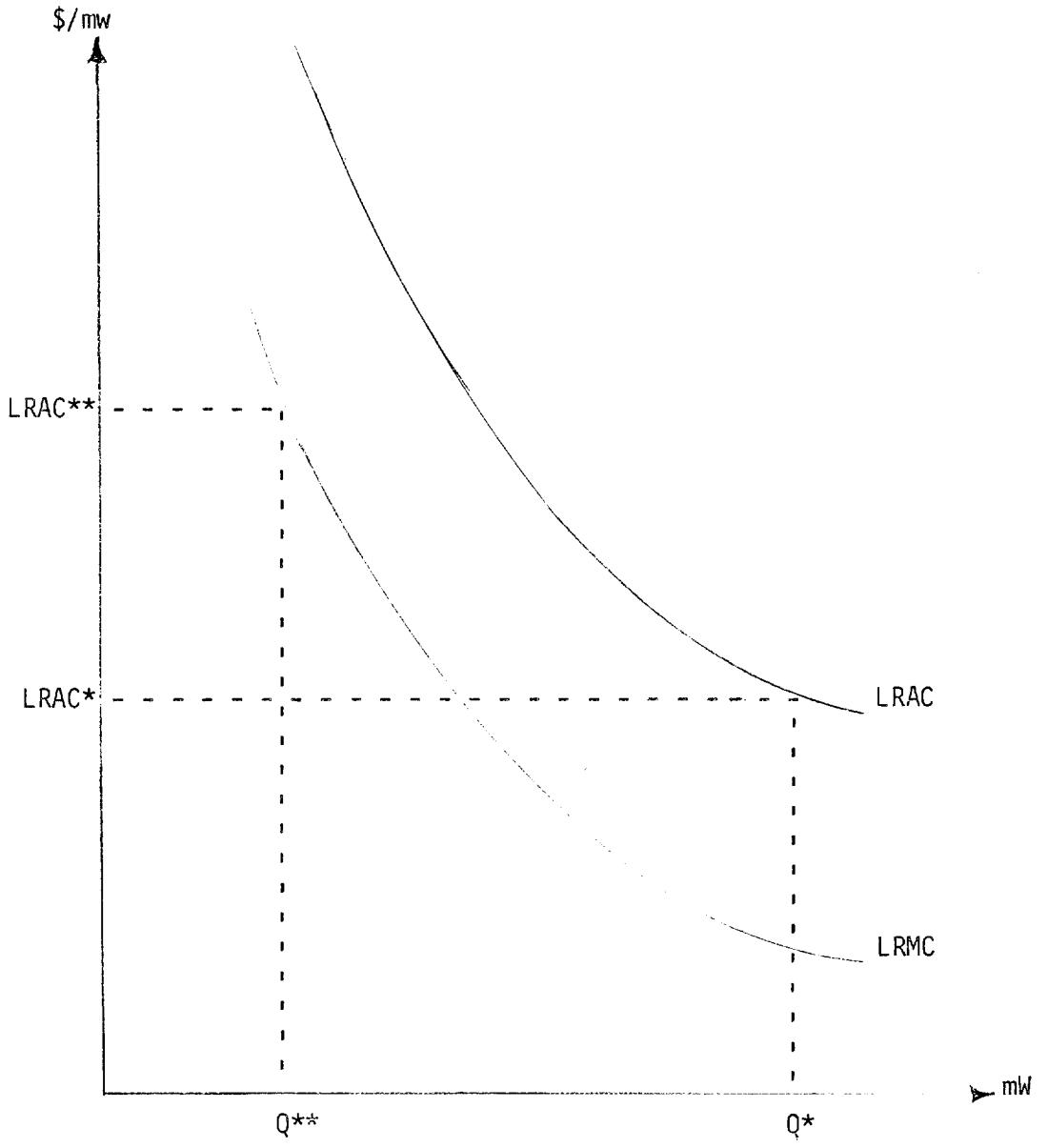

Fig. 2. Economies of scale in transmission service.

prices and product output that differs from the optimal set that would occur in a purely competitive market situation.[6]

If the natural monopoly is allowed to operate as an unconstrained monopolist, it typically would choose that strategy from a variety of pricing strategies which offers it the greatest probability of achieving its primary operating objective. For example, if its primary operating objective is to maximize profits, it may choose to employ discriminatory pricing techniques. That is, it might charge each customer the highest price that the customer would be willing to pay for each level of output.

A firm that is a natural monopoly may be able to maintain its monopoly because the government grants it exclusive production rights in a specified market. Because it is able to operate and make profits due in part to the government's intervention, the natural monopoly's pricing operations are generally restricted by a regulatory agency established as an arm of the government. The type of regulation that is generally imposed on a natural monopoly tries to limit the prices charged by the natural monopoly and/or to constrain the return on investment that the firm is allowed to earn. If regulation by the regulatory body is effective, the natural monopoly will be unable to charge maximum prices for each output level and will be constrained from earning the maximum potential return on investment. Maximum price regulation in a declining cost industry usually results in the firm setting a single maximum price for each good or service produced and satisfying the entire market demand for each good or service at the established price. Setting a maximum allowed return on invested capital yields similar price and quantity results as in the maximum price case. Under constrained return on capital regulation, return on capital and operating costs can be added together to determine the maximum

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6. See Mansfield, 1975, pp. 234-235. for the assumptions for pure competition. The optimality of prices and output will be discussed in Section 2.4.1.

revenue level that the firm can earn from the sale of a specified level of goods or services. Product prices can then be set by the regulatory body to meet specific regulatory goals or objectives.

The two regulatory schemes, therefore, are almost identical. In the maximum return on capital scheme, however, a firm has the ability to change its investment and cost structure so as to influence the price that it can charge. It has been suggested that such firms have a tendency to invest more heavily than is optimal and, therefore, raise the price that they can charge.[7]

The market structure of buyers to whom the natural monopoly sells can also affect its pricing and output behavior, regardless of the regulatory scheme imposed. For example, if the number of potential buyers for its products is small, the buyers of the firm's products may have considerable influence on the prices that the firm can charge. Such situations for one buyer and one seller are commonly referred to as bilateral monopolies.[8] The price levels determined by bilateral monopolies depend on the relative bargaining strengths of the two parties. In addition, if there exists alternative potential sellers of the products or substitutes for the products,[9] the seller's price may be limited to that price above which the buying firm would be induced to find another supplier. This type of pricing behavior is referred to as "limit pricing."

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7. Averch and Johnson, 1962

8. Fellner, 1949.

9. If a firm is buying power and transmission service separately, a substitute may be to buy the power involved from other sources. This may eliminate the need for the wheeling service altogether.

The final situation that may influence the pricing behavior of a natural monopoly is the situation in which the firm could be the seller of two products to the same customer. If the products are "tied" together so that a certain amount of each must be bought,[10] the price of one product may subsidize the price of the other. In such situations, the buying and selling firms are only interested in the total value of the transaction. The particular price of any one product may be inconsequential as long as the price of the other product is sufficiently high or low. Additionally, the selling utility could monopolize other products by tying. If one product is monopolized, the selling firm could require another product to be bought even at higher prices that other sources. Trebing believes that the transmission function is a focal point for such activity. "Control of this network permits the firm to limit or circumscribe the actions of possible competitors."[11]

3.4 Specific Costs Associated with Wheeling

Seven major types of economic cost may be created by wheeling transactions. These costs are:

1. The cost of producing power to replace line losses associated with wheeling;

2. Incremental transmission operating and maintenance costs;

3. Incremental real depreciation of transmission facilities;

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10. A firm selling power often has to transmit it for some distance over its own lines. The power cannot be bought without the transmission service so the two are "tied" together. Also, a firm could require that transmission and power be "tied" together, even though other power sources exist.

11. Trebing, 1977

4. Incremental capacity costs if the wheeling utility must add transmission capacity to carry out wheeling transactions;

5. A reduction in the quality of service to the wheeling utility's retail customers and firm wholesale customers if the wheeling transactions reduce the reliability of the transmission system or increase costs to maintain reliability at a given level;

6. Opportunity costs which result from the fact that other entities are unable to complete an economically efficient power interchange transaction because the transmission capacity of the intervening utility that must wheel the power is fully loaded; and,

7. Changes in utility operations, such as, unit commitment, economic dispatch, reserves, and unloaded generation.

The first type of economic cost is incurred by the utility that furnishes the wheeling losses, although payment for such costs is typically made by the utility purchasing the wheeled power. The second, third, and fourth types of economic cost may be incurred by the utility providing wheeling services. The fifth type may be incurred by the wheeling utility's firm customers whose electric service is interrupted more frequently as a result of wheeling transactions. The sixth type of economic cost reflects the higher cost of service incurred by other entities that are unable to complete cost-effective power transactions requiring wheeling services with the wheeling utility. The final cost can be incurred by any utility interconnected with the wheeling utility but usually are incurred primarily by the wheeling utility.

All of the major types of wheeling costs are defined in terms of marginal costs, not embedded costs associated with a utility's existing transmission system (e.g., taxes and insurance on gross transmission plant less accumulated depreciation reserve). Specifically, embedded costs of existing plants are irrelevant from either a planning or operating viewpoint. For example, when a utility can meet the demand for wheeling services with its existing transmission system, the utility incurs no

additional embedded costs by wheeling but may incur some of the marginal costs described above. On the other hand, if the utility cannot reliably meet the demand for wheeling services with its existing transmission system, the utility is faced with the decision of whether to add transmission capacity so that established reliability criteria are met. If the compensation, level of demand, and expected persistence of the excess demand are sufficient to justify the construction of new transmission facilities, the utility may incur the incremental cost of the capacity. However, if the compensation, level of demand, and expected persistence of the excess demand are insufficient to justify the construction of new capacity, the utility may ration access to its existing system by refusing to wheel those marginal transactions that lower the reliability of the transmission system below an acceptable level. Such rationing imposes a higher marginal cost of service (i.e., opportunity costs), as compared to the situation in which the wheeling took place, on the customers of the utilities that are refused wheeling services.[12]

3.4.1 Line Losses

In an alternating current (ac) transmission system, line losses increase by the square of the increased loading of a specific transmission line. If we assume that a specific transmission line is used to complete a wheeling transaction, the wheeling utility's incremental line losses may result in less power being delivered than is received by the wheeling utility. To account for those losses, a wheeling contract may call for the amount of power received by the wheeling utility to exceed the amount delivered by the estimated losses. In this case, the cost of the losses is the incremental generating costs of the utility

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12. For example, the inability of two utilities to complete an economy interchange transaction because third-party wheeling services are not available causes the combined operating costs of the two utilities to be higher than they would have been if the transaction had been completed.

selling the power. If the wheeling utility replaces the losses, the wheeling utility incurs a cost equal to its incremental cost of generating power to replace the losses.

As discussed in the previous chapter, electricity flows along the path of least resistance, which means that wheeled power may not flow along the shortest or most direct path between two utilities. Furthermore, systemwide transmission losses may increase, decrease, or be unaffected by a wheeling transaction. For these reasons, wheeling losses are typically based on systemwide analyses rather than on analyses of specific transmission lines.

Estimated losses may reflect either the incremental losses of the wheeling transaction or average system losses. Detailed load flow analyses, which are generally very expensive to perform, may be required to derive accurate estimates of incremental wheeling losses. Moreover, the value of such information on incremental losses for ratemaking purposes may be less than the cost of performing the studies. It appears that most utilities either assume that wheeling losses are minimal or use system average loss factors to estimate such losses. For example, if Utility B's system average loss factor is 10 percent and it delivers 10 mW of power from Utility A to Utility C in a given time period, Utility B typically requires Utility A to deliver 11 mW of power instead of 10 mW to Utility B's grid. This loss adjustment mechanism assumes that Utility A must generate sufficient power (11 mW) to enable Utility B to deliver 10 mW of power to Utility C as specified in the power interchange agreement between A and C. However, if the incremental losses created by the wheeling transaction exceed (are less than) the Utility B's system average losses, then Utility B would receive less (more) power than necessary from Utility A to adequately compensate Utility B under a wheeling agreement based on system average losses. This occurs because Utility B is contractually liable for delivering 10 mW of power to Utility C.

3.4.2 Incremental Transmission Operation and Maintenance Costs

A utility may also incur incremental transmission operating and maintenance (O&M) costs as a result of wheeling power.[13] These costs include the cost of scheduling and completing transactions, conducting load flow studies necessitated by the wheeling, and increasing the frequency of inspection of transmission equipment. Most utilities ignore incremental O&M expenses in setting compensation for the wheeling utility. Incremental O&M expenses incurred by the wheeling utility probably are quite low relative to incremental O&M expenses incurred by the utility producing the power that is wheeled. Nevertheless, an attempt can be made to estimate the magnitude of these expenses.

3.4.3 Incremental Real Depreciation

Incremental real depreciation costs are the accelerated reduction in the economic life of transmission facilities created by the use of such facilities in wheeling transactions. Discussions with utility operators indicate that such costs are never estimated under wheeling arrangements and are probably so low that the failure to estimate them has almost no effect on estimated costs.

3.4.4 Incremental Capacity Costs

As we noted earlier, a wheeling utility may incur incremental transmission capacity costs as a result of wheeling if new transmission facilities must be added to handle reactive loads

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13. We assume that any incremental administration and general (A&G) expenses created by wheeling transactions (e.g., billing expenses) are minimal. To the extent that they occur, they could be included in transmission operation and maintenance costs.

created by wheeling (e.g., the incremental cost of capacitors); to maintain system reliability (e.g., breakers and relays); meter and/or transform the wheeled power; and to eliminate transmission capacity limitations (e.g., new lines). These costs can be estimated in detailed engineering analyses of the impacts of wheeling on current transmission equipment needs and long-run marginal cost analyses of the utility's transmission system.

Some estimated incremental capacity costs can be associated directly with wheeling services to a specific entity. For example, a utility may construct a new line and install transformation equipment to ensure delivery of an entitlement to another utility. Under this situation, the utility receiving the entitlement creates the need for the additional transmission capacity.[14] However, most incremental capacity costs cannot be directly assigned and must be considered in aggregate as the joint incremental cost of providing transmission services to numerous entities.

3.4.5 Quality of Service

Wheeling transactions may also reduce the quality of service to the wheeling utility's firm retail and wholesale customers by creating system reliability problems resulting in increased service interruptions. For example, four major blackouts occurred in Florida during the first quarter of 1981. Many utility officials believe that the increased level of power interchanges and the associated wheeling transactions occurring under the energy broker system used by Florida's utilities were

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14. This statement does not imply that the utility receiving the entitlement power must pay the total cost of the new transmission capacity. For example, the new capacity may be used to wheel nonfirm power for other utilities or may provide reliability benefits to customers served by the owner of the capacity. In such cases, the new capacity provides several different services, and the problem becomes one of identifying the cost responsibility attributable to each service.

a direct contributor to these blackouts.[15] During these blackouts, it is reasonable to assume that firm wholesale and retail customers of utilities that were wheeling the power interchanges of other utilities incurred some economic costs because their electric service was interrupted. These costs include items such as the value of lost production that cannot be made up at another time and the loss of perishable items (e.g., refrigerated foods that spoil).

3.4.6 Opportunity Costs

The sixth type of economic cost that may be created by wheeling transactions is the opportunity cost of lost or excluded transactions. Opportunity costs are defined as the savings that have been foregone because a particular transaction was made. For example, assume that Utility A, which has an incremental operating cost of 30 mills per kWh, agrees to sell 10 mW of economy energy during a specific hour to Utility C which has a decremental operating cost of 70 mills per kWh. To complete the interchange transaction, Utility B must wheel the power from Utility A to Utility C. Ignoring losses and all costs incurred by Utility B, the savings or reduction in combined operating costs created by the transaction is $400.[16] Assume also that Utility D, which has an incremental operating cost of 40 mills per kWh, wants to sell during the same hour 10 mW of power to Utility E, which has a decremental operating cost of 60 mills per kWh. This transaction would reduce the combined operating costs of Utilities D and E by $200.[17] However, to complete the transaction, Utility B must wheel the power from Utility D to E.

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15. The probability of service interruptions caused by wheeling may be high in utility systems with relatively little experience in wheeling and in new power pools that rely on the facilities of one or two utilities to complete a multitude of wheeling transactions (e.g., Florida).

16. $400 = ($0.07/kWh - $0.03/kWh) * (10,000 kWh).

17. $200 = ($0.06/kWh - $0.04/kWh) * (10,000 kWh).

If Utility B has already agreed to wheel for Utility A and, as a result, has insufficient transmission capacity available in that hour to wheel for Utility D, the interchange between Utilities D and E will not occur and the $200 of potential operating cost savings will be lost. Even more important, if Utility B had agreed to wheel for Utility D instead of Utility A (e.g., if access to Utility B's transmission system was on a first-come, first-served basis), there would have been a loss of $400 in operating cost savings. Opportunity costs are economic costs but not direct costs to utilities participating in a wheeling transaction.

3.4.7 Costs Due to Changes in Utility Operations

Certain aspects of the operation of the utilities involved in a wheeling transaction may change as a result of the transaction. For example, the cost minimizing mix of plants operating may change due to the fact that power flows have been rearranged. Besides the mix of operating plants, changes may occur in unit commitments, reserves, and unloaded generation. These changes were discussed in depth in Chapter 2. The changes that occur in these items may result in additional costs and thus should be included in the costs of wheeling. These changes may also result in cost reductions.

3.5 Regulation of Wheeling Utilities

3.5.1 Economic Goals of Regulation

Effective regulation can significantly alter the behavior of a utility. However, a question exists as to what effective regulation should achieve. In particular, how should rates be set for utility services. With respect to setting rates for products and services offered by natural monopolies,

Bonbright[18] lists eight criteria for developing appropriate rates. These criteria are:

1. Simple, understandable, publicly acceptable, and feasible to apply

2. Free from controversies as to proper interpretation

3. Effective in yielding total revenue requirements under the fair-return standard

4. Capable of promoting revenue stability from year to year

5. Stable over time, with a minimum of unexpected changes seriously adverse to existing customers

6. Fair in the apportionment of total costs of service among the different customers

7. Avoid "undue discrimination" in rate relationships

8. Capable of promoting efficient uses of service with respect to:

   - total amount of service supplied by the utility

   - the relative uses of alternative types of service (e.g., on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line).

Bonbright considers the third criterion to be most important, followed by the sixth and eighth criteria.

Phillips,[19] in addition to the major ratemaking criteria of Bonbright, lists three additional goals of regulation.

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18. Bonbright, 1961, p. 293.

19. Phillips, 1969, p. 124.

Specifically, regulation should:

1. Ensure that service is provided to the maximum number of customers

2. Promote the development of industry in a region

3. Ensure public safety.

Recently a number of other regulatory goals have become important as the issues associated with them have received more attention from the public. Trebing[20] suggests the following goals:

1. Promotion of that form of industry structure most conductive to superior performance

2. Establishment of national priorities for curtailments and solutions to curtailments

3. Recognition and control of societal costs.

Deregulation and promotion of technological innovation are presently important issues in regulatory policy. Both have the possibility of lowering costs and have appeared to have worked in some markets. Trebing argues that the present structure in the utility industry preserves monopoly profits, fails to achieve maximum economies of scale, and dampens innovation. Regulators should be concerned, therefore, in how their decisions affect structure in the industry in order to avoid these problems.

The second goal suggested by Trebing has received emphasis due to the oil embargo, subsequent price shocks, and coal strikes. When emergency situations occur, it is often too late for policy decisions to be made and implemented. Prior planning can significantly reduce the costs of disruptions.

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20. Trebing, 1977

The final goal suggested by Trebing concerns environmental costs. The correct recovery of these costs are especially important when power is transferred over long distances (however, it is more important in the pricing of power rather than in the pricing of wheeling services) in that sometimes pollution problems are exported. An example is a mine-mouth coal plant (Four Corners) producing power for an area where pollution requirements are stringent (Southern California).

Other regulatory goals that have been considered by various regulatory agencies include:

1. Maintenance of the quality of service

2. Income redistribution through ratesetting

3. Establishment of uniform prices for all services provided by a utility

4. Lifeline pricing

5. Antitrust considerations

6. Oil conservation.

A number of regulatory goals can exist; the importance of each depends in large measure on the viewpoint of the individual. In this study. the goals will be limited to (1) those which apply most directly to price regulation of wheeling rates, and (2) those where a superior policy for achieving the goal's purpose does not exist. These goals, not necessarily listed in order of their importance, are the goals that will be considered:

1. Efficient use objective (Efficiency)

2. Fair cost apportionment or equity objective (Equity)

3. Practically and feasibility objective (Practicality)

4. Revenue requirement objective (Adequacy).

Methods other than regulation may exist to obtain the same objectives of many of the other regulatory goals but in a more direct or efficient manner than through price regulation of a particular industry. Reduction of monopoly franchises, restrictions to promote competition, or implementation of tax subsidies or tariffs, such as on imported oil, may achieve the same results as regulation with less conflicts with other goals.[21] Lifeline pricing, or ensuring that customers receive at least an amount of service necessary for survival, and increasing the number of customers do not apply to wholesale rates such as in wheeling. Likewise, the maintenance of quality of service is usually only a problem in increasing cost industries where the marginal cost is higher than the maximum allowable price.

3.5.2 Application of Regulatory Goals to Wheeling

Given the potential for wheeling transactions to create seven major types of real economic costs, how can rates be set to meet the four major regulatory pricing objectives discussed earlier? That is, what types of pricing mechanisms or compensation schemes:

1. Promote efficient use of transmission facilities and also indirectly promotes efficient power transfers?

2. Recover costs attributable to wheeling in an equitable manner?

3. Can be understood and implemented relatively easily?

4. Ensure that the wheeling utility is able to recover its transmission-related cost of service, including a fair return on its transmission plant and equipment?

We define and discuss issues associated with these objectives below.

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21. Posner, 1971.

Of course these goals may not be mutually consistent. For example, the information neccessary to implement an efficient rate structure (goal 1) may be impractical to obtain (goal 3). How well a particular rate structure achieves the various goals often is dependent on the weighting given by the regulatory process. Regulatory bodies are subject to pressures from a number of interest groups and must balance conflicting goals.[22] This has especially become apparent in the 1970's. "The pressure associated with consumer militancy has shown that equity and income distribution can no longer be considered on a subordinate and often subjective basis."[23]

3.5.2.1 Efficient Use

Efficiency, as usually used by economists, requires that resources obtain their best use. This usually occurs when price is equal to marginal or incremental cost. Incremental cost reflects the cost of the resources used to supply an incremental amount of service. If the service were not supplied, then those resources could be used for the production of another product or service; hence, incremental cost is sometimes referred to as the opportunity cost of a service. To some extent, the demand for all services and products is influenced by price. If consumers are to decide rationally whether to consume more or less of the product or service, then the price should reflect that which they are giving up. When the price of a good or service is set above its incremental production cost, some consumers who would have been willing to pay for the resources needed for the incremental production of the product or service will be unwilling to pay a higher amount. When this occurs, demand for the product will fall. Too few resources will be devoted to the production of the product; therefore, production and consumption of the product will be economically inefficient. Conversely, if

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22. See Stigler, 1971 for the classic paper on the conflicting pressures on regulators and Joskow, 1972, or Kasserman and Tepel, 1984 for empirical studies.

23. Trebing, 1977

the product price is below the incremental cost, consumers will pay less than the value of the incremental resources used to produce the product and consume more of the product. A price below incremental cost, therefore, causes to many resources to be used in the production of a product and the production and consumption of the product to be inefficient.

Interutility coordination and integration can be seriously affected if the efficiency goal is not achieved, especially if the pricing structure prevents certain transactions from occuring.[24] From an economic efficiency point of view, wheeling rates should be based on the marginal costs, not the fixed or accounting costs, of providing wheeling services. The marginal costs that should be considered are the long-run marginal economic costs. These costs include all costs a transaction would impose on the system over the long run. The costs are composed of operation, maintenance and capacity costs as described at the beginning of this chapter.

A wheeling transaction that can be interrupted at any time does not impose additional capacity costs on a system since they occur when there is unused capacity. Similarly, very short-term, non-interruptible transactions may not impose long-term capacity costs on the system unless there is an expectation that such types of transactions will occur in the future. Finally, long-term, non-interruptible transactions and transactions where facilities are required to be built incur substantial capacity costs over the long run and should be charged correspondingly.

When the demand for wheeling services exceed present available capacity at prices equal to long-term marginal costs, in the short-term it may be neccessary to ration available capacity. If the short run elasticity for wheeling services is small,

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24. For example, economy interchange transactions that may be economically efficient can be prevented if the pricing structures used by the potential participants in such transactions fail to reflect the incremental and decremental costs (i.e., marginal costs) of the participants.

prices may have to change drastically to limit demand to available supply.[25] When demand curtailments have been neccessary it usually has been met with priority systems. The Federal Power Commission (now FERC) used this method in the natural gas area[26] and it has been used with respect to petroleum sales at both the state and federal levels.

Unfortunately, such priority systems do not ensure economic efficiency (that is, resources obtain their best use). Oakland suggests that, "Optimal conditions call for the rationing of the good through user charges."[27] An auctioning process of the available capacity would ensure that the most valued use would obtain the use of the capacity because the bid for such use could be higher than other bids. Therefore, in situations where demand at long run marginal cost is higher than available capacity, an auctioning process could be implemented to obtain economic efficiency.

3.5.2.2 Fair Cost Apportionment or Equity

Fairness or equity serve as the basis for many of the cases before regulatory commissions and, therefore, they should be carefully considered. Failure to do so "would divorce theory from practice."[28] The goal of equity or fairness is limited here to the discussion of prices that should be charged for various services. Fairness and equity with respect to return on investment are discussed below under revenue requirement.

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25. see Acton, 1976 for a discussion of this problem related to final demands for electricity

26. see Trebing, 1977 for a discussion on the effects of this priority system

27. Oakland, 1972

28. Bonbright, 1961, p. 293.

A pricing structure is usually defined as fair or equitable in economic literature when the pricing structure does not unduly favor one set of consumers at the expense of another set. Unfortunately, this definition does not result in a set of unique prices. For example, if an existing transmission line runs between two large service areas, there exists a number of rates for other service areas along the line that could satisfy the fairness criteria. Any rate above the incremental cost of having an additional service area served by the line would reduce the costs to the two major service areas. One could say, then, that with respect to the two service areas, any rate above the incremental cost of the third service area is fair because other service areas are paying less than they would otherwise have paid.[29] Moreover, according to this definition, any allocation of common costs is fair because one allocation cannot be judged by economists to be superior to another.

This definition and belief that the allocation of non-incremental costs is arbitrary with respect to economic theory is fairly consistent throughout the economic literature. Fritz Machlup in Economics of Seller's Competition discusses the "impossibility of a rational allocation when the assumed objective is to determine the specific costs in a joint cost situation."[30] Bonbright states that "the only costs allocable ... to any given product or amount of product are differential costs."[31] Also, "whether or not the rate theorist should ... take part ... in controversies about rival standards of fairness is another question. The answer usually given by economists is in the negative, on the ground that the question, being one of ethics, goes beyond their professional competence."[32] Garfield and Wallace state that "joint costs are incapable of 'accurate' or 'certain' allocation among respective

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29. Faulhaber, 1975.

30. Machlup, 1952

31. Bonbright, 1961, p. 298

32. Bonbright, 1961, p. 133

types of service."[33] Even the Supreme Court subscribed to this view in Colorado Interstate Gas Company v. the Federal Power Commission, "Allocation of costs is not a matter for the slide rule ... It has no claim to an exact science."[34]

When a specific allocation of joint costs is suggested in the literature a particular social welfare function must be assumed. This literature is related to the optimal tax literature. Feldstein[35] and Munk[36] discuss this issue.

Other definitions of equity or fairness exist. One is that equity or fairness means equality. Two variations of this definition exist. The first variation assumes that, based on quantity of power delivered, regardless of costs, total costs of transmission should be allocated equally. The second assumes that common costs should be allocated equally based on the quantity of power delivered.

The first variation implies that transmitting 1 mWh is a particular service and its price should be the same for all purchasers of that service. This argument fails to consider that transmission service is not a single product but has time, voltage, and distance dimensions. For example, transmitting power during off-peak periods over a short distance is considerably less costly, and thereby different, than transmitting power during system peak periods over a long distance at distribution voltage.

The second variation refers only to the allocation of common costs. Any identifiable costs are borne by the customer who imposes these costs. Other common (or joint) costs are then allocated based on the use of the particular customer. Such

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33. Garfield and Wallace, 1964

34. Colorado Interstate Gas Company v. the Federal Power Commission, 324 U.S. 581,589 (1945)

35. Feldstein, 1972

36. Munk, 1977

allocation schemes have been shown to discourage wasteful use and duplicate facilities[37] but may not promote all cost-justified use. Therefore, they may not be efficient.

Another definition of equity concers the ability of certain groups to pay. In effect, rates become a method of income redistribution (as discussed previously this is sometimes considered a goal of regulation in itself). For example, it may be believed that residential customers (or a predominantly residential utility), since they cannot pass higher costs onto customers, are less able to pay for rate increases than commercial or industrial customers. Therefore, their rates should be set lower.

A related definition concerns the willingness of certain groups to pay. In this definition it is considered fair or equitable to charge lower rates to those who may consume substantially less or even stop consuming at higher rates. It is believed that the service is "worth" more to those more willing to pay for the service and that they should pay what the service is "worth". However, other factors enter into this pricing structure. Even if the customers paying the lower rates pay only some of the joint costs associated with the service, the rates for the other customers are lower than if the first group did not buy the service. Also, with a one-part rate, it can be shown that welfare in the market is maximized under such rate structures (this point will be discussed later).

A final definition involves the equity or fairness of payment for externalities associated with producing a service. Using an example used in the previous section, consider pollution from a power plant which occurs substantially locally. There may be a belief that it is only fair that if the power from the plant is transmitted elsewhere, then those distant communities should pay relatively more than local consumers. The higher distant rates would be used to lower local rates as compensation for the pollution the local inhabitants must bear (efficiency would

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37. see Tschirhart, 1979, for a proof of this statement

require that all consumers pay more and the same rate, except for transmission costs).

A number of government agencies (such as the U.S. Army Corps of Engineers) use a pricing method where a customer class is charged its identifiable incremental cost plus its proportional share of joint costs. The proportional share is determined by the cost of the facility if it were built solely to serve the particular class, divided by the sum of such costs for all classes. This is believed to be fair and equitable since each class's costs are dependent on the costs that would be incurred if the class were alone. This is referred to as the solitary incremental cost.

Each definition has its adherents, but economic theory cannot definitively decide between the latter definition (that is, without an explicit social welfare function). Economic theory can only give guidance to the effects of such definitions on other goals of regulation. The particular choice between these definitions are and should be political decisions. The definition used here will be that usually used in the economic literature and no recommendation will be made with respect to the allocation of joint costs.

In these definitions of fairness, the term "free rider" is often used in reference to those customers who do not pay the fair price. In the definition used by most economists, this would mean a customer who does not pay the identifiable incremental cost that he imposes on the system. The strictly uniform pricing definition would refer to a customer as a free rider when he pays less than a uniform price. A high income customer not paying a higher rate than the average rate would be termed a free rider from the ability to pay definition.

3.5.2.3 Practicality and Feasibility

Practical attributes and freedom from controversy are probably not as important in large wheeling transactions as in retail rates but may be as important in small wheeling transactions. In large transactions, the costs imposed by a failure to meet these specific goals may be minor in comparison to potential

benefits, although the failure may cause significant delays in a utility's being willing to buy or sell wheeling services. An aspect of practicality and feasibility is revenue and rate stability. As demonstrated by contracts negotiated in the past, these aspects are of varying importance. For example, some contracts specify that wheeling charges shall be calculated from split-savings, thereby varying hourly. Other contracts specify long-term fixed charges.

The main obstacle to practicality in wheeling rate structures is the amount of information required and the quality of the information on which to base the rates. Accurate information not only leads to ensuring that other goals such as efficiency are met, but also, can alleviate significant controversy concerning the rates. If wheeling rates are to be cost based, substantial analysis (as discussed in Chapter 2) must be performed to determine these costs. Even determining the facilities used by a transaction may require computer modeling. If rates are based on the ability or willingness to pay, determining these factors with a high enough level of precision to avoid challenges may be impossible.[38, 39]

3.5.2.4 Revenue Requirement

The revenue requirement objective implies that a utility should be allowed to recover its transmission-related costs. Without this objective, utilities would not have the incentive to maintain or add transmission facilities. The lack of incentive would seriously affect the significant potential cost savings

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38. The telephone industry routinely overcomes these problems, but the U.S. Postal Service has difficulties in basing rates on demand analysis. The U.S. Appeals Court of the District of Columbia rejected such demand elasticity based rates in National Association of Greeting Card Publications vs. the U.S. Postal Service, Civ. No. 75-1856-U.S. Appl. D.C. Cir. F. 2nd, Dec. 28, 1976

39. See Willig, 1979; Sherman, 1979; and, Huettner, 1982 for examples of implementation of Ramsey pricing

and reliability benefits that can be achieved through greater levels of coordinated utility operations.[40, 41]

This objective focuses on a utility's transmission-related revenue requirement, which is based on invested capital costs and the extent to which prices for wheeling services contribute to the recovery of this revenue requirement. Under current ratemaking practices at FERC (and at most state regulatory bodies), the level of profit that a utility is allowed to earn is constrained by three factors: its embedded (accounting) cost of plant and equipment used to provide electricity to customers; the return allowed on these investments; and its operating expenses. These constraints are typically set for an historic or projected 12-month period called a test year. Using test-year billing information and the established revenue requirement, rates are set to produce the revenue requirement. Part of this ratemaking process is the "functionalization" of costs into generation, transmission, distribution, and general cost categories. In the discussion that follows, we assume that: (1) a utility serves only wholesale customers, which eliminates the problem of segregating costs by retail and wholesale regulatory jurisdictions; and (2) a utility's transmission-related cost of service and revenue requirement can be identified using the functionalization process and the rate of return allowed by FERC on the utility's capitalized investment costs and expenses.

The revenue requirement is basically payment for factor inputs. The setting of the allowed revenues by a regulatory body involves all of the previously discussed goals of regulation. There are problems associated with efficiency, equity, and practicality. Rather than the efficiency of end user prices, the efficiency problem here is with inputs. If a utility is not able to recover certain costs associated with wheeling, use of facilities for wheeling and new investment for wheeling may be limited. If this occurs, resources would not obtain their best use and inefficiencies would result.

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40. MacAvoy, 1974, pp. 293

41. U.S. Department of Energy, 1980.

Since the utility must absorb committed costs which are not covered by rates from profits, the rate of return on investment would decline. The rate of return on investment is the payment for this factor of production. If the payment is too low the firm would probably disinvest in the facilities used.[42] Inadequate returns lower the value of stockholder equity.[43] In effect, low rates are paid for by the value of stockholder equity. Therefore, the question of fairness and equity arises and the answer depends on the particular definition of fairness and equity. The definition developed in the section on end-use price equity would imply that investment be priced at its marginal cost. "The economist, taking as his model the equating of price and marginal cost, would begin by identifying as the 'correct' return the one that covers the cost of (incremental) capital."[44] On the basis of the ability to pay definition, it is sometimes argued that a company (that is, its stockholders) should be able to absorb lower profits rather than customers paying higher rates.

In trying to achieve the goals of efficiency and equity, the goal of practicality arises. The problems associated with these goals are: (1) how are the costs determined and allocated; (2) how is the value of investment determined; and, (3) how is the rate of return determined. The first question was discussed under the efficiency of end-user prices. There are generally

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42. If investment occurs present stockholders would have their earnings diluted and the value of their holdings would decline. Therefore, if the firm's management has the interest of present stockholders in mind, investment will not be made. However, regulatory bodies can force investment (see Kahn, I, 1970, p. 42).

43. In addition to the effects discussed in the previous footnote, the value of stockholder equity can decline even without new investment. Since disinvestment requires time, a firm can continue operating even when this is occuring. The low earnings would themselves lower the value of equity since the value is determined by the present value of future earnings (see Kahn, I, 1970, pp. 58-60).

44. Kahn, I, 1970 p. 43

three methods to determine the value of investment: market value of equity, embedded cost, and reproductive costs (the cost of reproducing current facilities). Since a higher percent return leads to a higher market value of equity and hence (if the level of the return stays constant) a lower percent return, using the market value would lead to circular results. This method, then, cannot be used. Given that the facilities used by a wheeling transaction are known, estimation of embedded or reproductive costs are straightforward to calculate. The question then becomes which one of these two methods should be used. Since the crucial factor for equity holders is the total level of the return generated, either of the two latter methods may be used with equal results if the rate of return is consistent with the measure of investment.

Determining the rate of return, though, is difficult to accomplish. The problems are: whose rate of return to use as a benchmark and over what time period should it be measured. Generally, it is believed that the return of "comparable" companies with "comparable" risks should be used.[45] However, the procedure eliminates the incentive for a company to do well. If a company is well managed, comparative companies would be well managed. These companies would have a lower cost of capital and rate of return since they would be less risky. An improvement in management, therefore, could lead to a lower rate of return. The use of "comparative" companies, then, must be balanced with the need to maintain incentives.

The time period over which the rate of return of comparative companies is observed is another important aspect of determining the rate of return for a regulated firm. Inflation and interest rates have become volatile over the past decade. This influences the rate of returns for "comparable" companies. Not only, then, must companies be used to determine the rate of return, but also, comparable time periods. Otherwise, significant over or under recovery of returns may arise. The uncertainty associated with determining the rate of return is

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45. The U.S. Supreme Court affirmed this principle in "Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591,601 (1944).

large and the behavior and performance of the firm is an important indication of whether the rate is too small or too large.

3.5.2.5 Balancing Regulatory Goals

As mentioned previously, the goals of regulation may not be mutually consistent. Marginal cost pricing required for efficiency may over or under recover revenues required to meet a fair return on investment. Such pricing, moreover, satisfies the definition of equity used here but does not neccessarily satisfy other definitions of equity. This section discusses the implications of trying to achieve a balance between the regulatory goals.

In a purely competitive market situation, each consumer faces a uniform price; each producer is able to recover its total cost of production; and no unit of output is sold below its marginal cost. Therefore, a competitive market price is not only efficient, but it is also equitable. With decreasing marginal costs over the entire range of outputs, price must be set above marginal costs to recover total costs. Thus, equity issues arise along with efficiency issues in developing a compensation scheme for transmission services.

The economic literature has been discussing the balance between efficiency, equity and adequacy since at least the 1870's. A number of authors argued that low prices in elastic markets could recover at least some consumer costs and maintain the firm's profits thus leading to lower prices for everyone.[46] This type of price discrimination is now commonly referred to as Ramsey pricing and was shown to maximize consumers' and producers' surplus given that an adequate return must be made and a <u>one</u> part pricing structure. Ramsey's article on this topic appeared in 1927 in the Economic Journal.[47] Given the

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46. Alexander, 1887

47. Ramsey, 1927

requirements, resources are used optimally and the pricing method can be called "second best" efficient.

Boiteux in 1951 presented a more formal analysis[48] and was able to abstract from using consumer surplus. In a 1956 article[49] Boiteux was able to employ a Pareto optimality approach and was able to eliminate all need of inter-personal comparisons of utility. Since that time a number of other authors have been able to refine the proof of the "second best" efficiency of this type of pricing.

This type of pricing methodology suffers from three major problems: (1) it is only efficient in a "second best" sense; (2) the practical implementation of this pricing methodology for wheeling services may be impossible; and, (3) the criteria for equity according to various other definitions may not be fulfilled. Since prices are adjusted away from marginal costs, the actual level of consumption of a service may be far different than the true "efficient" level. How far these differences may be depends on the elasticities of the demands. Since wheeling is usually a relatively small proportion of the total cost and cost savings of a power transaction (usually power costs and cost savings are higher) and usually no close substitutes for wheeling exists (transmission facilities are limited and usually require the full or partial participation of the utility's service area the transmission line traverses, that is, one often must have the wheeling utility's concurrence on building substitute lines), we would expect the elasticity to be low.

Determining the actual elasticities, though, may be difficult. Therefore practical implementation of the pricing methodology may be impossible. Elasticities probably differ not only from the above factors but also on the duration of the service and the nature of the service (firm or interruptible, see Chapter 4 for definitions of these terms).

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48. Boiteux, 1951

49. Boiteux, 1956

Long-term service may have more substitution possibilities (such as, new transmission lines or new generating facilities, although the lead times for these facilities are now considerable) and, therefore, a higher elasticity than short-term service. Interruptible service (since the utility must have alternatives available if the service is interrupted) also has more substitution possibilities and probably higher elasticities than firm service. The elasticities are also influenced by the proportion of total costs and cost savings wheeling represents in the overall power transaction. The higher the proportion the more that derived demand for the service is affected and the higher the elasticity. Since all of these factors are utility and even transaction dependent the estimation of the elasticities are difficult if not impossible to determine.

The third problem associated with the Ramsey pricing methodology is failure to agree with certain definitions of equity. Non-cost based differential pricing (price discrimination) is often regarded as inequitable. Ramsey pricing can produce substantial price differences of this type. However, if prices are adjusted upward to account for underrecovery of revenue, then according to the definition of equity used here one cannot say that there is an inequitable price structure.

Another alternative price structure that can be used to balance the regulatory goals is a multi-part (usually two-part) rate structure. The two-part rate structure is usually composed of a constant marginal price per unit consumed and a fixed annual (or monthly) fee sometimes called an admission fee. "If the marginal price is set equal to the marginal cost and the resulting annual charge does not cause any potential customers to prefer no purchase at all, the allocation of resources is Pareto efficient."[50] Problems associated with this type of pricing involves ensuring that potential participants are not dissuaded by the fixed charge and distributional aspects associated with the charge. If one entry price is charged some small transactions may be excluded. However, multiple blocks

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50. Feldstein,1972

based on usage for the annual charge may be used to overcome this problem with no decrease in efficiency if the blocks and demands are sufficiently polarized so that crossover between blocks does not occur.

Any rate structure that is based on costs (as are optimal Ramsey and two-part rate structures) have serious practicality problems associated with wheeling transactions. Accurate cost information, as described in Chapter 2, may have to be obtained from computer simulations. For small, short lead time transactions the simulations may inhibit the transactions from occuring.

3.6 Conclusion

In the long run wheeling services exibit declining costs. Seven specific economic costs can be attributable to wheeling. The regulatory question is how to practically recover these various costs in an efficient and equitable manner. Efficiency is defined as resources obtaining their best use. This is usually obtained when price is equal to marginal or incremental cost. Economics can give little guidance to equitable distribution of costs beyond identifiable marginal or incremental costs. Practicality in the rate methodology is neccessary for implementation. Finally, the adequate recovery of investment is needed to maintain investment in facilities and equity with respect to stockholders. All of these sometimes conflicting objectives must be balanced by the regulatory body.

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Chapter 4

Existing Wheeling Arrangements

4.1 Introduction

This chapter is a review of Appendices I through IV which are detailed discussions of existing wheeling arrangements, of major FERC proceedings involving wheeling arrangements, and of institutional factors affecting wheeling arrangements. Appendix I is discussed first and contains an overview of all wheeling arrangements on file at FERC, federal marketing agencies, the Power Authority of the State of New York, and the State of Texas. The next appendix discussed, Appendix II, is an in-depth analysis of a sample of 52 FERC wheeling arrangements. The arrangements are described, the utilities' rationale for specific terms are given, and the arrangements are evaluated as to how well they meet the goals of regulation established in Chapter 3. Appendix III is then reviewed. This appendix describes the major FERC proceedings involving wheeling and how the issues were resolved. Finally, Appendix IV in which the institutional aspects of wheeling are stated, is reviewed.

In general, the wheeling arrangements studied show wide variations as to their terms and conditions. Also, the terms and conditions are such that it is uncertain how close they meet the goals of regulation and appear to be rather restrictive. The relaxation of these restrictions could give way to a freer and more competitive market for bulk power.

4.2 Description and Classification of Wheeling Arrangements

There are over 1,000 wheeling arrangements on file at various agencies in the United States. These arrangements fall into one of two categories: tariffs and rate schedules. Tariffs are arrangements which do not specify particular participants but usually are open to certain classes of wheeling customers. Rate schedules, on the other hand, are between fixed and specified participants. The arrangements usually include:

1. type of transmission service;

2. compensation methods and rate forms;

3. specific requirements for service;

4. notice and response requirements; and,

5. other miscellaneous requirements.

Most of the arrangements are filed at various federal and state agencies. The largest group are those filed at the Federal Energy Regulatory Commission (FERC) and comprise most of the arrangements in which investor owned utilities are the providers of the wheeling services. The federal marketing agencies, such as the Alaska Power Administration, Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration, and the Western Area Power Administration, also have large numbers of wheeling arrangements on file but some overlap those on file at FERC. Arrangements where investor owned utilities are providing services to the marketing agencies may be on file at both the agency and at FERC. The Tennessee Valley Authority (not a federal marketing agency, but rather, a federal corporation) participates in one wheeling arrangement. The New York Power Authority (a New York State agency) participates in a number of wheeling arrangements within and around New York State. Finally, the Texas Public Utility Commission has regulatory authority over wheeling arrangements

among Texas utilities which are not interconnected outside the state and an arrangement filed with them.

4.2.1 FERC Wheeling Arrangements

The wheeling arrangements at FERC were examined to determine their terms and conditions. FERC had 768 arrangements that satisfied the definition of wheeling in Chapter 2 of this document. Rate schedules (arrangements between specific parties) comprised 98 percent of the FERC arrangements while tariffs (arrangement usually open to all customers of a specific class) comprised the remainder. The arrangements were broken down into firm arrangements and nonfirm arrangements. Firm arrangements comprised 79 percent of the arrangements. The compensation methods used in the arrangements were almost balanced between specific fixed rates (for example, $x per kWh) and rate formulae.

Few arrangements (15 percent) had restrictions on the specific lines which were to be used, delivery voltages, or what the buying utility could do with the power. Similarly, most arrangements did not specify specific notice requirements for initial service start (11 percent) or the response by the wheeling utility to that initial request for service (four percent). However, many (42 percent) stated a particular time period for notice of permanent termination.

4.2.2 NonFERC Wheeling Arrangements

Similar to the FERC wheeling arrangements, the wheeling arrangements at other agencies were reviewed to determine their terms and conditions. Rather than a complete survey, however, a sample of approximately 50 percent of the wheeling arrangements were examined. The reasons for the sample and description of the sampling process are described in Appendix I.

Eighty-three percent of the arrangements were wheeling with separate compensation for the wheeling service. A significant portion of the arrangements were tariffs.

The terms and conditions of the wheeling arrangements were markedly similar to those of the FERC arrangements. Firm arrangements comprised 79 percent of the arrangements versus 79 percent for the FERC arrangements. Specific one-part rates were used in 69 percent of the arrangements and rate formulae were used in 20 percent.

Once again, few arrangements had limitations on the particular lines that could be used, or the delivery voltage. A substantial number though, had limitations as to whom the power could be sold. The only notice requirement that was contained in a significant number of arrangements was notice for permanent termination (45 percent).

4.2.3 Classification System

The wheeling arrangements examined can be classified into their two major characteristics:

1. The right of the wheeling utility to interrupt or curtail the wheeling service, and

2. The method used to compensate the wheeling utility.

The right of intervention separates the arrangements into what is usually referred to as firm and nonfirm arrangements. The compensation method divides the arrangements into four basic types:

1. Specific fixed rate (compensation is based on a per time unit or per quantity unit transmitted)

2. Rate formula (compensation is based on a formula and may vary from one point in time to another)

3. Split savings (gains from the wheeling transaction are shared by the participants), and

4. Banking or reciprocal arrangements (payment is made in-kind).

The specific fixed rate compensation method is the only one where the actual rate can be determined in advance. It can be further subdivided dependent on the units upon which the rate is based. These categories are shown in Figure 4.1.

Due to the necessity of consulting secondary sources to determine the appropriate classification of the wheeling arrangements (some important information is not included in some of the wheeling arrangements), a sample of wheeling arrangements was classified. There were 200 FERC wheeling arrangements and 176 nonFERC transmission arrangements selected for classification. Due to a change in the definition of wheeling, some nonwheeling arrangements are included in the sample.[1] Because of the complexity associated with rate formula arrangements, they were excluded from the classification. The number of FERC transmission arrangements falling into the classification categories is shown in Table 4.1, and the number for nonFERC transmission arrangements is shown in Table 4.2.

The table for the FERC arrangements reveals that four types of transmission rates (annual and monthly charges, one-part rates, and mileage rates) are used most often to compensate transmission utilities. Of these arrangements, it appears that utilities offering firm transmission services with a one-part rate are equally likely to use a mills/kWh charge, a $/kW-year charge, or a $/kW-month charge. On the other hand, all but two of the 39 one-part rates for nonfirm transmission services use a mills/kWh charge.

The nonFERC arrangements show significant differences from the FERC arrangements. First, the arrangements have a higher concentration of one-part rates than the FERC arrangements. The one-part rates are much more likely to use mills/kWh than other types of charges. Many of these arrangements, also, are tariffs as opposed to rate schedules. The tariffs are used much more often with nonfirm transmission arrangements that with firm arrangements. Finally, the rates appear to be lower for the same type of service than the FERC arrangements.

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1. See Appendix I for details on which nonwheeling arrangements were included.

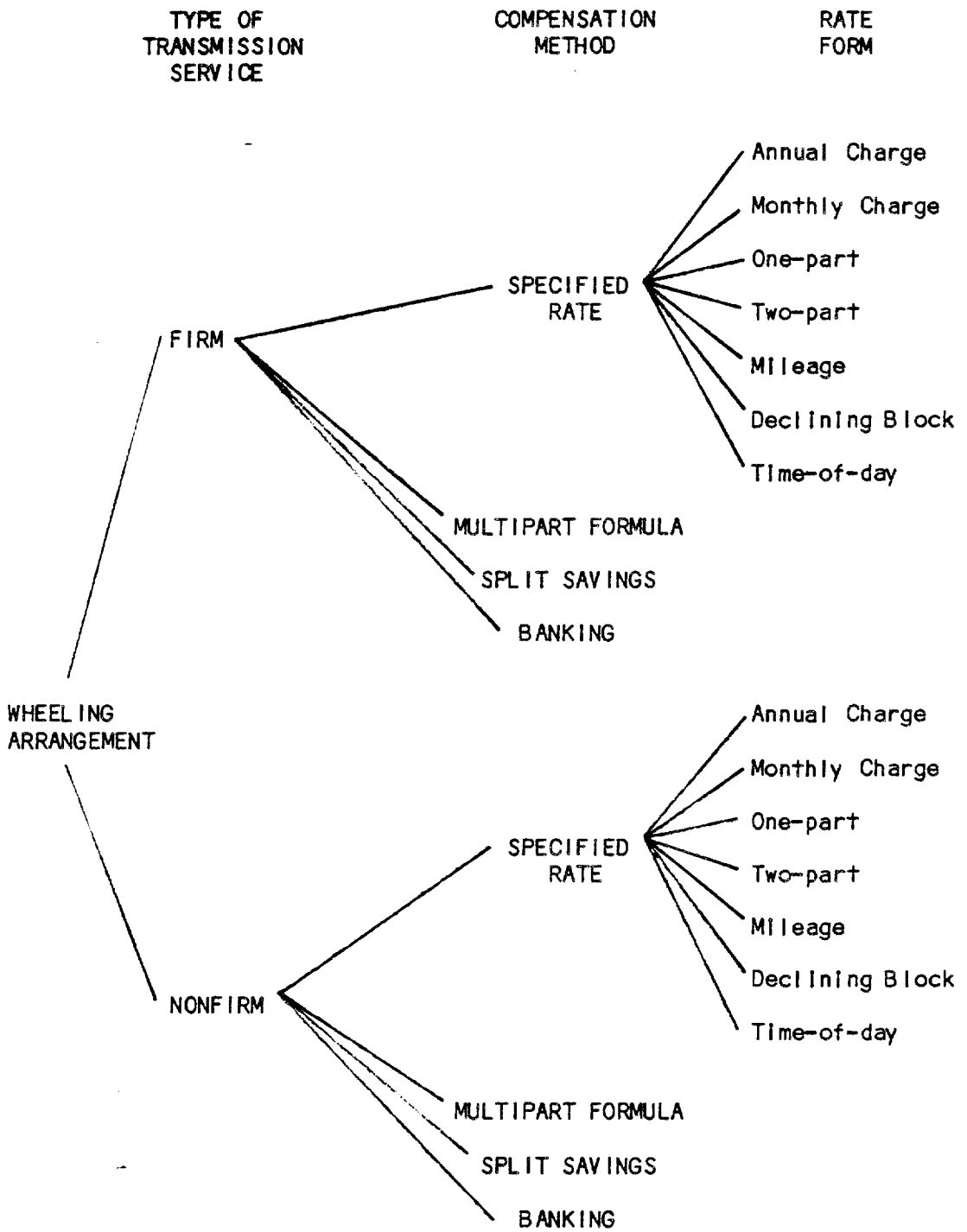


Fig. 4.1. Classification categories

Table 4.1. Compensation methods/specific fixed rate forms for firm and nonfirm transmission services filed with FERC.

Compensation Method/ Specific Fixed Rate Form	Transmission Service: Firm	Nonfirm	Total
Annual charge	5	0	5
Monthly charge	15	2	17
One-part	106	39	145
Two-part	1	0	1
Mileage	28	0	28
Declining-block	1	0	1
Time-of-day	1	0	1
Split-savings	0	1	1
Banking	1	42	1
TOTAL	158	42	200

Table 4.2. Compensation methods/specific fixed rate forms for firm and nonfirm transmission services filed with non-FERC agencies.

Compensation method/ specific fixed rate form	Transmission service		
	Firm	Nonfirm	Total
Annual charge	0	0	0
Monthly charge	12	0	12
One-part (Tariff)	13	29	42
One-part (Rate Schedule)	81	31	112
Two-part	6	1	7
Mileage	3	0	3
Declining-block	0	0	0
Time-of-day	0	0	0
TOTAL	115	61	176

4.3 Detailed Examination of Wheeling Arrangements

In order to obtain additonal information on the existing wheeling arrangements, a small sample of the wheeling arrangements identified in the previous section were selected for detailed examination and evaluation of their terms and conditions with regard to the goals of regulation established in Chapter 3. The arrangements were not selected randomly but rather selected according to four criteria. These criteria in order of importance are:

1. all general wheeling tariffs;

2. diversity with respect to the type of entities involved in the arrangements;

3. diversity with respect to the terms and conditions in the arrangements; and,

4. geographic representation.

Some of the arrangements had two different types of wheeling services contained within one agreement; that is, both firm and nonfirm services were offered. The services have different price structures and terms and conditions so they were treated as separate arrangements. The total number of arrangements that were examined then, was 52.

4.3.1 Type of Transmission Service Available

There are basically two types of transmission services that were offered in the arrangements, firm and nonfirm. Firm transmission service refers to service which can usually only be interrupted for:

1. specific kinds of emergency situations created by factors not under the control of the utility, for example, weather related failures;

2. possible impairment of the operation of the selling utility's system when the utility is operating responsibly; for example, unanticipated power flows threatening stability of the system;

3. scheduled maintenance; and,

4. violation of an important term or condition of the arrangement by other parties to the arrangement.

Nonfirm service, on the other hand, is service which the selling utility can interrupt at any time at its discretion. In the sample, the two types of service were almost equally represented. There were 27 firm arrangements and 26 nonfirm arrangements.

The distinction between firm and nonfirm is not as clear as it may appear at first. For example, some of the nonfirm arrangements had conditions on when they may be interrupted. These types of arrangements can be referred to as conditionally nonfirm.

The major concern with respect to the type of service offered is the effect of the goal of efficiency. Because of the long-term nature of some of the firm arrangements, adjustments to new conditions may not occur as rapidly as efficiency may require. Also, the limited types of service that are offered may have a dampening effect on the free trade of bulk power.

4.3.2 Compensation Methods and Rate Forms

Among the firm type wheeling arrangements almost two-thirds were one-part, specific rates based on kW's. The remainder of the arrangements were divided among the various rate forms. Three used a one-part rate form based on kWh's. The most interesting method of setting rates were those of the power pools in which no charge was made or the charge did not accrue directly to the purchaser of wheeling services.

Approximately one-third of the nonfirm wheeling arrangements were one-part rates based on kWh's. Surprisingly though,

another third were one-part rates based on kW's. As in the case with firm arrangements, the remainder of the arrangements are divided between the other rate forms. The power pools also have examples of no direct compensation for wheeling services.

With few exceptions, the arrangements are cost based and, therefore, to some extent meet the goals of efficiency, revenue requirement, and fair cost apportionment. However, with one exception the rates are not based on load flow studies and the basis for determining the cost basis may not be strong. As shown in Chapter 2, the most direct route for transmission may not be the lines that are used in a transaction. The relatively simple methods of compensation that were observed certainly, though, satisfy the goals of practicality and feasibility.

4.3.3 Specific Requirements for Service

The specific requirements for service can be divided into four areas:

1. Entities eligible for service;

2. Connection requirements;

3. Delivery voltage; and,

4. Special Equipment costs.

Of particular concern for competition in the area of bulk power sales is who can obtain service and what can be their role in the particular arrangement. For example, if surplus transmission capacity exists, are there limitations as to the direction in which power can flow? Can a buyer of power become a seller if he wishes? Usually no such restrictions are placed on power flows. Tariffs usually are less restrictive than rate schedules, as would be expected since the participants are not usually specified. Limitations may restrict competition in power sales and retard efficiency, but there may be severe problems with the practicality of allowing reverse power flows. The effects on the wheeling utility may be quite different. Limitations on the participants for similar transactions may be overly restrictive in that practicality would be the same for all participants.

Connection and voltage requirements may specify which interconnections flows of power must go through and the voltage that must be used at those connections. Approximately 30 percent of the arrangements limit interconnections to two (one at the receiving and one at the delivery points) while 20 percent limit deliveries to one specific voltage. Usually various interconnections and voltages are specified but they are limited to those specified. As with limitations on entities eligible for service, there are two conflicting goals to achieve. The first is efficiency in that bulk power sales are not limited. The other is practicality. With many interconnections and various voltage delivery points the effects on the wheeling utility may be difficult to determine. However, since so many utilities specify various connections and voltages this may not be a problem.

In order to obtain wheeling services, sometimes utilities are required to purchase and install special equipment. Examples are transformers, switches, capacitors, or meters. Few of the wheeling arrangements specify the equipment required but rather specify who is responsible for the cost of the equipment. Even so, only 25 percent of the arrangements mention such costs. Of the arrangements which specify who will pay for the costs, almost half specify the buyer of the power or wheeling services. If the equipment is used solely for wheeling services, efficiency and fair cost apportionment would require the entire amount be paid by the firm purchasing wheeling services. However, as is the case with most transmission equipment, other transactions use and benefit from the equipment. These joint costs should be distributed among the users of the equipment in a manner similar to other transmission equipment.

4.3.4 Notice and Response Requirements

Notice and response requirements allow for the orderly phase in or phase out of wheeling transactions. They allow the utilities to plan and adjust their systems to the new transactions. However, it is possible that they may also be used to limit

access to transmission facilities. For example, in very short-term power purchases it may be crucial to have the wheeling services available quickly. Delays in arranging these services may prevent the power purchase from being made. The major types of notices and response requirements are:

1. Notice by buyer for initial start of service;

2. Response by seller for initial start of service;

3. Scheduling notice for transactions;

4. Notice for interruption of scheduled service; and,

5. Notice for permanent termination.

Both the notice by buyer for initial start of service and the response by seller for initial start of service determine the lead time for a wheeling transaction. This time is important in that the wheeling utility can analyse the effect of the transaction on its system and correct for any problems that may occur. However, it may also be used as a delaying tactic by the wheeling utility if it does not desire to provide service at that particular time. Few wheeling arrangements specify time limits for these notice requirements, and, if they do so, use vague language such as, the response must be "prompt". Depending on the use that is made of specific notice and response requirements efficiency could be increased or decreased. The nonexistence or vagueness of the language in current wheeling arrangements indicate that currently they have little influence on wheeling transactions.

The two most important notice requirements are scheduling notices and notices for interruptions. Scheduling notices inform the wheeling utility of the amount of power and the time during which the power will actually be wheeled. Most of the wheeling arrangements mention these two types of notices. However, as in the case of the other notices, the language is usually vague. "Scheduling notices should be given promptly" and "reasonable notice should be given for interruptions" are common phrases in the arrangements. A number of arrangements, however, do specify exact requirements for these notices. For

planning purposes these types of notices are important, and efficiency probably could be increased if they were more specific.

The final type of notice, termination notice, is the time period (or in some cases the date) required for ending the wheeling arrangement. Similar to the other type of notices, few arrangements actually mention this type of notice. Those that do mention this type, as opposed to the other types of notices, usually specify exactly the time period required. The most common time period is six months. If efficiency requires the elimination of constraints on buying and selling of power, then termination notices by their very nature would interfere with efficiency. If efficiency is to be achieved, there is no reason to terminate wheeling arrangements. The arrangements could be modified, but with the right pricing structure all utilities should maintain their arrangements.

4.3.5 Miscellaneous Requirements

Miscellaneous requirements in wheeling arrangements include limitations on the type of power that can be wheeled, losses and reactive power clauses, and other special terms and conditions which may be in the arrangements. Almost half of the arrangements surveyed placed limitations on the type of power that could be wheeled. The limitation on the type of power that could be wheeled ranged from nonspecific (such as firm or nonfirm) to specific (such as unit power). Restrictions on the type of power that is wheeled may limit the type of power a buying utility can purchase, thus interfering with efficiency. Appropriate pricing policies can be used to make certain that the revenue requirement of the wheeling utility is met even if there is uncertainty as to the amount of power that may actually be wheeled.

Approximately half of the wheeling arrangements have clauses that mention losses and/or reactive power. Losses refer to the power that is lost through resistance of the transmission lines or other transmission equipment. Usually, losses are a fixed percentage of power transmitted and commonly are average system losses. Without load flow studies, estimates of losses may be

significantly different from the losses actually incurred. Therefore, basing charges on loss estimates may violate efficiency and fair cost apportionment.

Reactive power is power which flows back to the generating units and provides no useful work. Such power can cause severe instability for a transmission network. When the wheeling arrangements mention reactive power they usually specify that it cannot fall above a certain level or interruption of service may occur. Some arrangements specify charges for reactive power. The potential cost of reactive power in most systems probably would be so high that the present method of requiring utilities to limit reactive power to a certain amount would satisfy the regulatory goals.

About one-third of the arrangements mentioned special terms or conditions for wheeling power. Such terms and conditions were usually very specific to the utilities involved in the transactions and therefore, no overall statement can be made concerning them. Usually, the areas that they cover are minor and probably would not interfere with the goals of regulation. One specific term of interest, though, is in one arrangement that requires all disputes to be solved by binding arbitration. This increases the practicality and feasibility of the arrangement, in that disputes can settled quickly without lengthy negotiations or litigation.

4.4 Description of Major FERC Proceedings and Orders

The terms and conditions in wheeling arrangements can arise from either agreements between parties or as a result of regulatory decisions. Most of the terms and conditions are of the former type. This section focuses on some of the terms and conditions which have been litigated at the FERC and decided by the Commission. From this information, the position taken by the FERC can be summarized on some of the major issues involved in wheeling services.

This section outlines the results of seven FERC cases: Cleveland Electric Illuminating Company, Opinion 84, Docket No. ER75-194, (CEI); Otter Tail Power Company, Opinion 93, Docket Nos. E8152 and ER77-5, (Otter Tail); Kentucky Utilities Company, Opinions 116 and 116-A, Docket No. ER78-417, (KU); Southeastern Power Administration vs. Kentucky Utilities Company, Docket No. EL80-7, (SEPU vs. KU); Florida Power and Light Company, Opinion 152, Docket Nos. ER77-175 and ER78-19 et al., (FP&L); Pacific Gas and Electric Company, Opinion 143, Docket No. ER76-532, (PG&E); and Limits for Percentage Adders in Electric Rates for Transmission Services, Order 84, Docket No. RM79-29, (Percentage Adders). The issues presented in each case, the positions of the parties involved, and the Commission's decision are outlined in Appendix III. This section summarizes the FERC's decisions by issue rather than by case. The focus is on the Commission's ruling instead of the controversy that preceeded it. Therefore, the section provides a guide to the Commission's interpretations of appropriate regulations of wheeling.

4.4.1 Rate Base

Four of the cases addressed the problem of determining the appropriate rate base for transmission services: CEI, Otter Tail, FP&L and PG&E.

The CEI case involved a tariff filed by CEI which would allow rural electric cooperatives and municipal systems to wheel power through CEI. One of the provisions of CEI's rate base calculations was to include distribution high-side breakers and capacitors. The Commission pointed out that CEI needed to show that this equipment would have been installed for transmission even if there had been no distribution function. Since CEI's witness could not confirm this assertion, the investment was to be allocated to distribution.

The Otter Tail case was the first time that the Commission had to deal exclusively with establishing a rate for wheeling services. A major issue of the case concerned the facilities that should be included in the rate base. The major subissues included whether or not the following should be calculated as a part of the transmission rate base: (1) transmission lines and step-up transformers; (2) the incremental cost of relocating a

planned plant; and, (3) oil circuit breakers, line sectionalizing switches, and capacitor banks. The Commission ruled that the rate base should not be limited to transmission facilities actually being used to serve current wheeling customers but should include the whole transmission system because all of the lines were potentially useful in providing wheeling services. FERC also agreed that the equipment at the distribution substation did serve a transmission purpose and should be included in the rate base. However, the Commission rejected the interpretation that since the location of the plant at Jamestown rather than Big Stone saved Otter Tail from building new transmission lines, the increased construction costs should be considered a transmission rather than a production expense. The Commission stated that there are a number of factors which influence plant siting. Thus, the allocation of a portion of those costs to transmission would be arbitrary.

The FP&L cases involved a number of issues concerning wheeling arrangements between FP&L and several municipal utilities in Florida. As in Otter Tail, the question was what portion of the transmission facilities should properly be included in the rate base for wheeling customers. The Commission accepted FP&L's rolled-in approach under which all transmission facilities were included in the rate base except for two minor categories (facilities operated at 69 kv and facilities at generating plant substations associated with stepping up voltages to transmission levels). In an integrated system, all transmission facilities are involved to some extent in wheeling transactions. Therefore, these facilities can properly be included in the wheeling rate base.

The PG&E case involved a determination of the wheeling rates that PG&E should charge the Central Valley Project (CVP). One of the questions addressed in the case was whether the entire PG&E and CVP systems should be considered jointly in determining the rate base for the calculation of transmission costs. PG&E had the responsibility for dispatching both its own and CVP's power over the combined system. However, the two systems were not built to operate together, PG&E could operate independently of CVP, and PG&E did not have the right to use CVP's system. The Commission rejected a combined system costing approach and

ruled that wheeling costs should be determined using the traditional cost of service method.

4.4.2 Other Wheeling Costs

Four of the seven cases addressed cost of service issues other than the determination of the rate base. These cases involved CEI, Otter Tail, KU and PG&E.

One of the disputed issues in the CEI case involved how to allocate system control and load dispatching costs. In its calculation of the cost of service, CEI estimated that the transmission function should include distribution load dispatching expenses, power supply system control and load dispatching expenses. The Commission found that CEI had to be consistent in its treatment of its accounts. Since CEI had chosen to spread out the costs of system control and load dispatching into three accounts (distribution, transmission, and production), it could not then decide to allocate all of these expenses to the transmission function for the purpose of the tariff.

In addition to the examination of the rate base issue, the Otter Trail case involved other cost-of-service questions. The first involved whether jointly-owned facilities should be included in the calculation of system load. The Commission ruled that the facilities should not be included in the system load estimate and that electric revenues from the partners should be deducted from the cost of service. This allocation was consistent with the Commission's ruling that the line segments built by the company's partners should not be included in the rate base or considered in the calculation of the cost of service. A second question involved Otter Tail's methodology for estimating the cost of service in the test year. The Commission felt that Otter Tail had not shown that its methodology for estimating a 19 percent increase in transmission expenses was reasonable. Since the company's figures were so much higher than the historical estimate of approximately 3 percent, the Commission felt that there was serious doubt as to the reasonableness of Otter Tail's approach. The Commission rejected Otter Tail's calculations.

The KU case was filed by the City of Paris, Kentucky (City) to protest a rate increase by the Kentucky Utilities Company (KU) for wholesale power purchases. This case does not specifically apply to wheeling as defined in this study. However, the controversy involved transmission costs and demonstrates the Commission's view on these costs. A major issue was whether the City should bear some transmission capacity costs even though they were receiving power and transmission services that could generally be interrupted at will. The Commission ruled that the City should not be charged transmission capacity costs because of the interruptible nature of the service. There was no evidence that KU had built additional transmission lines to be able to serve the City. Other decisions by the Commission that had allocated transmission capacity charges involved firm power arrangements.

The PG&E case addressed the use of intangible reliability credits in the cost of service calculation. Since the Central Valley Project (CVP) and PG&E systems are interconnected, PG&E may realize higher reliability. If the power transmitted on a PG&E line for PG&E must be curtailed, it may be possible that CVP's lines could be used. The proposal under consideration involved a 5 percent credit for CVP's transmission system for the increase in reliability to PG&E. The Commission felt that PG&E did win some intangible benefits of increased reliability from the CVP system and allowed the credit.

4.4.3 Rate Design

Rate design issues, including the way that per unit charges are determined, were addressed by the Commission in three cases. Otter Tail, FP&L, and PG&E involved a discussion of how rates should be structured given agreement on the rate base and the cost of service.

In the Otter Trail case, rates were calculated based on annual peak demand. The Commission found that this procedure was inappropriate because the demand figure for allocating costs was calculated using coincident peak demands at hour intervals whereas the customer's share of costs were calculated using non-coincident peak demands at quarter-hour intervals. This inconsistency of approach could lead to overcollections. The

Commission approved the adoption of a rate design in which the actual peak demand of the month (or 90 percent of the customer's peak demand during the preceeding 11 months, whichever is higher) determined the wheeling rate. This 90 percent rolling-rachet approach was judged to be consistent and it had been used in other rate designs.

In the FP&L cases, one of the rate-design issues involved whether there should be a joint tariff with Florida Power Corporation (FPC), since a number of transactions required services from both companies. The Commission decided that it may only rule on the level of individual rates (which were not shown to be too high in this case), non-competitiveness was not demonstrated, and a joint rate would be discriminatory against the other customers. Another rate-design issue in the FP&L cases was the correct allocation of demand costs. Proposals included the use of an average of 12 coincident peaks, a single coincident peak and an average of 12 monthly non-coincident peaks. The Commission decided to require a 12-month average non-coincident peak method because estimating coincident loads would be difficult and such a method would more accurately reflect the costs involved.

The PG&E case introduced the possibility of establishing wheeling rates using DOE's Delta Method. The Delta approach is a way to calculate appropriate increases to a base rate. It is a fixed-formula calculation based on cost increases over the past five years. The Commission found that the use of the Delta Method in this case was inappropriate. If the parties to the contract under which the conditiions for wheeling services were outlined had intended the use of this fixed-formula approach, it would have been included in the language of the contract. Therefore, the Commission determined that the cost of service method should be applied.

A second rate design issue was addressed in the PG&E case. Historically, the rate was an energy charge (mills/kWh). It was suggested that the rate be changed to a cents/kW rate because costs are more dependent on maximum load factors and the revenue derived could remain the same as the mills/kWh rate. The Commission decided that the kWh rate should continue, citing that it was used for 30 years and the arguments for a change were not convincing.

4.4.4 Billing Determinants

In addition to its discussion of wheeling rate design, the Otter Tail case also included a discussion of how customers were billed. Otter Tail had been basing its billing procedures on an estimated annual peak demand: the previous winter's greatest 15-minute demand was used for the first 6 months; a 7 percent load growth factor was applied to this value to estimate the highest demand for the next year's annual winter peak, and this estimate was used for the remaining 6 months of the year. If the estimated peak was found to be inaccurate, then Otter Tail would adjust the charges retroactively. The Commission found that the 7 percent load growth factor was reasonable. Even if it had not been, the adjustment would insure that the estimated billing was corrected, if necessary. However, since Otter Tail's rate design was ruled to be inappropriate, the billing procedure was not to be used, either.

4.4.5 Type of Service

The Commission has addressed the distinction between firm and nonfirm service (FP&L) in one case.

The FP&L case concerned what is firm service and whether nonfirm service should have demand charges. The services under consideration were short-term firm, that is, it was for short periods of time and once accepted it could not be interrupted. The Commission decided that the service was nonfirm since the municipal utilities could be refused the service at the time of the request, but ruled that they should be allocated demand charges, since, once accepted, FP&L is committed to using its transmission system for that duration.

4.4.6 Availability of Service

The tariff provisions proposed in the CEI case gave CEI a great deal of discretion regarding how service would be made available. The tariff provisions involved: form of notice, sole discretion, curtailment and minimum reservation period. Under the tariff provisions for form of notice, CEI did not have to

justify its denial of service to potential customers. The Commission ruled that CEI should be required to give oral notification of the reasons why transmission service was to be denied, followed within three days by written confirmation.

The sole discretion issue arose with CEI's assertion that it would be the sole judge as to whether or not transmission services were available. The Commission decided that this language allowed for the possibility of arbitrary curtailment. The use of phrases such as "sole discretion," "sole judge," and "sole judgement" were ordered deleted from the tariff.

The third issue involved curtailment. CEI did not specify how potential transmission capacity shortages would be allocated. The Commission required that the tariff specify the procedure CEI would follow if curtailment became necessary.

Another service-availability issue in the CEI case concerned the minimum reservation period for wheeling service. The Commission decided that there was no reason why short-term rates and terms should be different and since CEI already offered short-term service, the minimum period should be one week.

4.4.7 Restrictions on Service

The CEI case also addressed the problem of tariff restrictions. CEI indicated that the rates and provisions outlined in the tariff applied only to wheeling services for municipal utilities and rural electric cooperatives. The Commission did not feel that transmission services should be made available to a larger group of possible electricity producers (such as cogenerators) and purchasers (such as irrigation districts) under this tariff's provision. If CEI refused to wheel power for a producer or to a purchaser, that party could then request intervention from FERC.

4.4.8 Power Factor

The FP&L case involved a discussion of an appropriate way to handle power factors. FP&L had included a vague clause requiring the wheeling customer to maintain its power factor as close to unity as possible. An alternative approach would be to

include a specific clause which outlined the minimum acceptable power factor and the penalty for not achieving the minimum. The Commission decided that both approaches were vague and approved FP&L's provision. However, if a transmission service customer violated the reactive power clause, FP&L was required to make a Section 205 filing before invoking any penalty or nullifying the contract.

4.4.9 Percentage Adders

A percentage adder is an incremental charge tacked on to the price of purchased power. The Percentage Adders hearings examined this rate feature and confirmed that when transmission takes place over a number of utility systems the adder compounds. The Commission proposed a rule that would limit percentage adders to one mill per kWh. Hearings were held and the final rule issued in Order Number 84 on May 7, 1980.

There were two major disputes at the hearing which were of interest to this study. The first was what purposes are served and what costs should be recovered with percentage adders. The Commission's preliminary position in the hearings was that the adders should only recover incremental costs that are difficult or expensive to quantify. Witnesses at the hearing stated that utilities used the adders as compensation for all costs (even fixed costs) or as an incentive to engage in wheeling above fully allocated costs. The Commission ruled that adders based on purchased power prices are not cost justified, but adders less than one mill can usually be shown to be cost justified. Therefore, percentage adders less than or equal to one mill do not have to be cost justified but adders above one mill must show cost justification.

The proposed rule would have limited percentage adders in all electric rate schedules. Several people who commented at the hearing suggested that the rule be limited only to transmitting utilities and should not apply to bilateral, interchange transactions. The Commission limited the rule only to "transmission or third party resale of electric power." They asserted that they will continue to study the use of percentage adders to bilateral, interchange transactions.

4.4.10 PURPA Wheeling Requests

Subsections 211(a) and (b) of the Federal Power Act provide means through which applicants may seek an order from the Commission requiring an electric utility to provide transmission services to the applicant. Under Subsection 211(a), the Commission may issue an order if a derived benefit such as "in the public interest" can be demonstrated. Subsection 211(b) provides the means for the applicant to seek an order when a request for transmission service has been refused. Under Section 212, the requested order must pass "negative" tests; that is, the Commission cannot issue an order unless it finds that the order would not result in certain harmful effects. At issue in the SEPA vs KU case was whether these PURPA standards had been met. The Commission decided that it could not order KU to provide the petitioned transmission services on the basis of a failure to meet the PURPA standards.

4.4.11 Miscellaneous Conditions

A couple of additional issues of interest to the analysis of wheeling but which do not fall under the earlier categories deals with (1) the need to plan for the future transmission capacity needs of wheeling customers and (2) the save harmless clause.

The CEI case addressed the issue of whether CEI should include the needs of the buyers of wheeling services in their future transmission plans. The Commission agreed with the position that if CEI did not take into account these needs, then CEI would be in violation of the operating license agreement and that the users of the wheeling service would be uncertain whether the service would be available to them in the future. The Commission decided that wheeling customers' load growth must be included in future capacity planning.

The FP&L case addressed the problem of liability. FP&L included a clause in its interchange agreements which would protect FP&L from paying penalty charges on claims from parties involved in wheeling transactions, even if FP&L could be shown to have been guilty of negligence or wrongdoing. The Commission felt that FP&L should be responsible for claims arising out of the

company's own negligence and wrongdoing. Although the save harmless clause was ordered changed, the Commission ruled that FP&L should not be subject to liability for actions taken by the buyer or seller of the interchange power.

4.5 Institutional Aspects of Wheeling Services

Special institutional aspects of the relationship between utilities can have influences on the terms and conditions in wheeling arrangements and the appropriateness of those terms and conditions. This section reviews the terms and conditions of wheeling arrangements within power pools, holding companies, and the Federal Marketing Agencies that are significantly different from normal wheeling arrangements.

4.5.1 Power Pools

For power pools and holding companies, the most important differences from normal wheeling transactions are in the area of wheeling rates. The incentives associated with such transactions differ greatly from normal transactions. The rate structures that evolved in some of the power pools reflect the differences in incentives.

Two of the most closely coordinated power pools do not directly charge for wheeling services for economy power (NEPOOL and NYPOOL). Until recently, the other closely coordinated pool in the U.S., the PJM pool, also did not charge for economy power wheeling services. When users of wheeling services are not directly charged for those services, the obvious conclusion is that without the price mechanism too much wheeling service is being demanded, and, without cost based rates, too little or too much wheeling service is being supplied depending on the degree of compensation for transmission services.

However, the individual utilities do not make decisions on wheeling services, but rather, the power pool through their decisions on power generation and capacity planning. Charging

the individual companies for wheeling services would place the incentives and disincentives of the pricing structure at the wrong decision-making level. The costs of transmission should be considered, therefore, in the pool's cost minimizing decision process.

Another problem is the vast number of wheeling transactions that are made in highly centralized pools. It may be difficult to quantify the costs involved in all of the wheeling transactions that may occur. In conclusion, in the case of power pools, the compensation methods may be justified.

4.5.2 Holding Companies

Holding companies are similar to power pools in that generation and capacity planning are centralized in the company. The individual subsidiaries usually do not have authority in these decisions. Therefore, they are not influenced by charges for wheeling services. The costs of transmission, therefore, should be considered at the level that decisions are made, that is, at the holding company level.

4.5.3 Federal Marketing Agencies

Federal Marketing Agencies are identified and their wheeling arrangements described in Appendix I of this report. There is little difference between their wheeling arrangements and those of others with the exception of the higher incidence of tariffs and simpler rate schedules. In contrast to investor owned utilities, there is little regulation of the Agencies. Their wheeling arrangements only have to be in the "public interest." that is, they have to return the public's investment. No compelling reason was found that there should be special differences between the Marketing Agencies' wheeling arrangements and those of other entities.

Chapter 5

Alternatives to Existing Wheeling Arrangements

This chapter reviews the information presented in previous chapters with respect to the terms and conditions of existing wheeling arrangements and suggests other alternative approaches. These alternatives are evaluated regarding how well they meet the criteria of:

1. efficient use (efficiency);

2. equity or fair cost apportionment (fairness);

3. achievement of the revenue requirement (adequacy); and,

4. practicality and feasibility (practicality).

The chapter is organized similar to Section 4.3 where a detailed examination of existing wheeling arrangements was presented. The terms and conditions were divided into the following categories in that chapter:

1. type of transmission service available;

2. compensation methods and rate forms;

3. specific requirements for service;

4. notice and response requirements; and,

5. other miscellaneous requirements.

Each of these terms and conditions are discussed separately in the following sections.

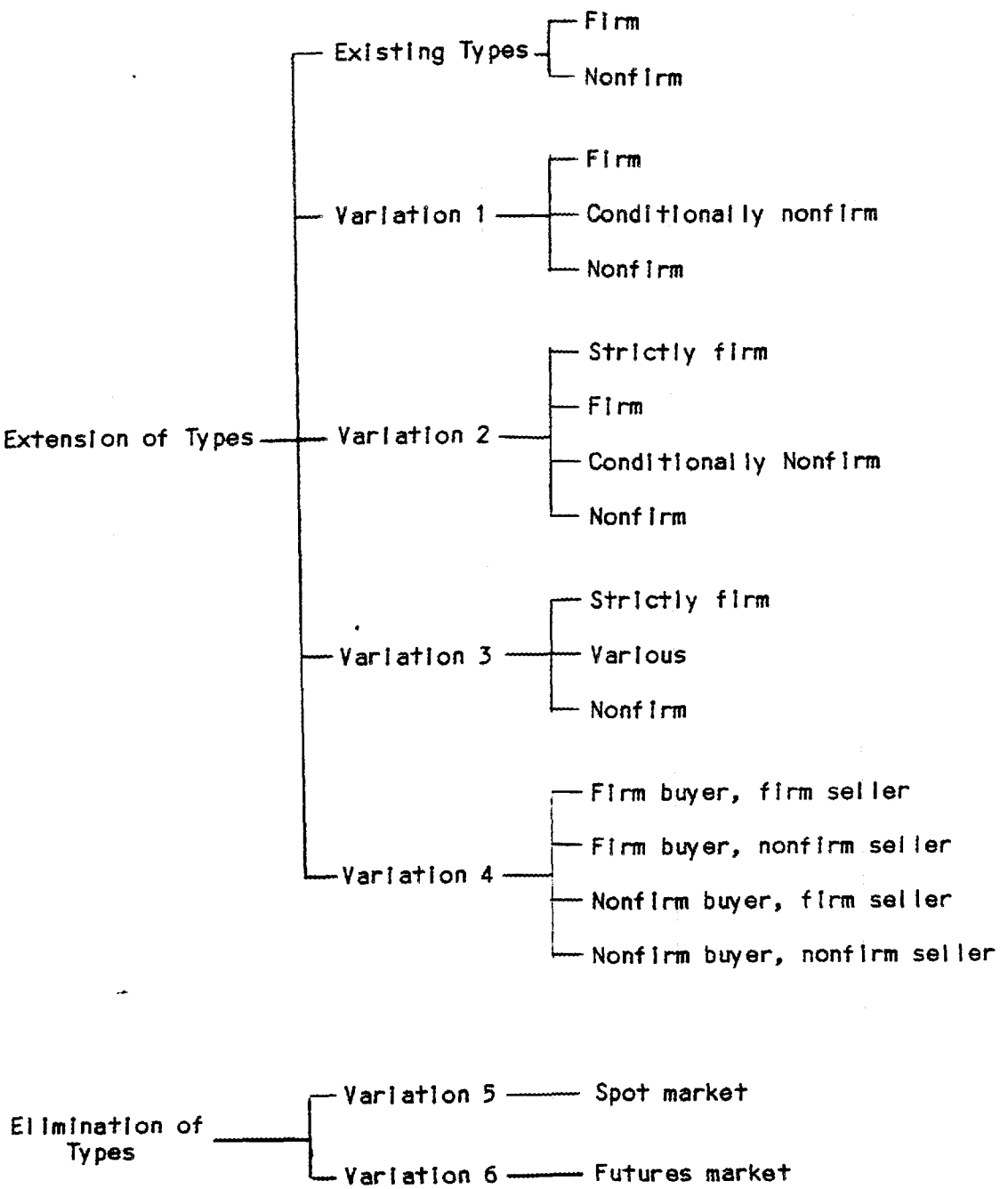
Not all of the aspects of these terms and conditions will be discussed since alternatives to all of them were not found. An example is reactive power. Utility spokesmen (as discussed in Appendix II) warned that the reactive power factor should be as close to one as possible, otherwise the stability of the transmission system would be threatened. Any alternative may, therefore, prove impractical.

5.1 Type of Transmission Service

In most cases, present arrangements are divided between firm and nonfirm types of service. However, as shown in Section 4.3 the degree of firmness in some nonfirm arrangements vary. In a number of arrangements, restrictions are placed on the ability of the wheeling utility to interrupt service. All types of arrangements have their strengths and weaknesses when they are evaluated according to the criteria of efficiency, fairness, adequacy, and practicality. Existing arrangements were evaluated according to these criteria in Section 4.3.

Alternatives to these types of arrangements fall into two broad categories: (1) extending the existing two types to a variety of types; and, (2) dropping the designation of types. These categories, their subcategories and the relations between them are shown in Figure 5.1. Under the first category of alternatives a variety of new types can be developed. A limited addition would be to add conditionally firm (or nonfirm) to the categories (variation 1 in Figure 5.1). This would be similar to many arrangements now in effect in that some conditions on interruptions are placed on the wheeling utility. A further addition would be to add strictly firm (variation 2 in Figure 5.1) where the wheeling utility would be required to construct new capacity if needed for the transaction. Finally, the number of arrangements could be extended by categorizing conditionally firm into various subcategories based on their degree of firmness (variation 3 in Figure 5.1). For example, interruptions due to the need of the wheeling utility to maintain the integrity of its own system is more firm (is more restrictive,

Figure 5.1 Types of transmission services



that is, less likely to occur) than interruptions due to the needs of other wheeling customers. More restrictive conditions would lead to a category being ranked firmer.

These alternatives are the same or similar to existing arrangements with the exception of strictly firm. Each adds to the options available to the parties and therefore efficiency may be increased if transactions were prevented in the past due to a failure in consideration of these types of arrangements. Adequacy and fairness are not applicable to the type of arrangements in that they are concerned primarily with prices. Practicality is applicable especially with regards to strictly firm service. Strictly firm may not receive wide acceptance in that the buying utilities may prefer joint ownership projects so that more control of transmission facilities are maintained and they can include the facilities in their rate base.

Another alternative concerning extending the number of types would be to rank types based on the degree of firmness both from the buyer and seller side (variation 4 in Figure 5.1). Most existing arrangements specify restrictions on interrupting the supply of wheeling service. This would extend the types of service to the ranking of restrictions on when the power being wheeled can be interrupted by the other parties in the wheeling arrangement (either the supplier or purchaser of the power being wheeled). This would usually take the form of guaranteeing a certain amount of revenue for the wheeling firm, although to prevent problems on the system, it may be used to prevent sudden changes in power transmitted. The former is commonly in use where contracted demand or "take or pay" contracts are used for billing purposes. The latter form can be important where wheeling by displacement is important. Each are important if capacity decisions must be made by the wheeling utility. In order for a wheeling transaction to occur, new lines or even new generating facilities might have to be built. Guaranteeing use of such facilities by the other parties of a wheeling transaction may be an important incentive to the wheeling utility to engage in the transaction.

Efficiency is increased if new transactions can occur that under previous conditions would be prevented from occurring. Practicality would be enhanced in that billing would be

simplified. Additionally, the risk of not receiving adequate compensation by the wheeling utility for the transmission system investment would be decreased.

The second broad category alternative for wheeling arrangements is the elimination of types. Existing arrangements guarantee price but service has differing degrees of firmness. The price, for a particular type of service, may be still applicable but at certain times (with certain types, conditionally firm and nonfirm) service can not be obtained.

In the first alternative of this type, service is always guaranteed but price varies (variation 5 in Figure 5.1). When demands approach capacity, rather than allocating capacity based on the supply of service it would be allocated by price.[1] This type of pricing is sometimes called "spot market" pricing.[2]

The price adjusts continuously to reflect the cost of supplying the service. Therefore, the price is equal to marginal cost and efficiency is realized. Two major problems exist in the practical implementation of this type of wheeling arrangement. The first is the determination of prices. Accurate measurement of marginal cost may be difficult to achieve especially if they must be continuously updated. For small, infrequent transactions, it may not be cost effective to accurately determine the marginal cost. The second problem is the large variation in price that may have to occur to balance demand and capacity. In the short-term demand may be very inelastic requiring substantial price jumps to balance the system. Alternatively, as with existing nonfirm types of arrangements, substantial costs may be incurred for standby generation for the utilities buying power in order to avoid incurring sharp jumps in wheeling rates.

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1. If a complete breakdown of service occurs, price may become infinite, therefore, the service demanded at that time would be zero and all services demanded would be satisfied.

2. See Bohn (1982) and (1983) for further description of this methodology.

A variation on guaranteeing price versus guaranteeing service would be to have all wheeling service nonfirm and then have a futures market for the reliability of that service (variation 6 in Figure 5.1). By this method the users of wheeling service can choose the degree of firmness in price and reliability of service not only from the supplier of wheeling services but also from other parties. At times when service may have to be curtailed, the sellers of the futures contract may have to obtain service for the holder of the contract by bidding service away from other users. By this method, the wheeling utility or the user of the wheeling service do not have to accept all of the uncertainty in providing firm service.

This alternative is similar to the previous alternative with the exception that buyers of wheeling services can guard against changes in prices through the futures market. Efficiency is maintained since price is equated to marginal cost.[3] In addition, by paying a premium they can obtain a specified level of service. With respect to practicality, this may avoid the costs of standby generation service for those utilities which would rather have stable service and prices. However the problem of determining costs continuously and its effect on practicality still remains, as in the previous case. Additionally, it is questionable whether an orgainized market in future contracts can be formed.

5.2 Compensation Methods and Rate Forms

The most common existing compensation method is a specific fixed rate of either kW for firm or kWh for nonfirm wheeling service. Rates are determined by a fully allocated cost methodology.

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3. In Stumpp (1981) it is shown that for end use sales of electricity there must be two prices, one for usage and one for reliability, in order to have efficiency for both of these two aspects of electicity service.

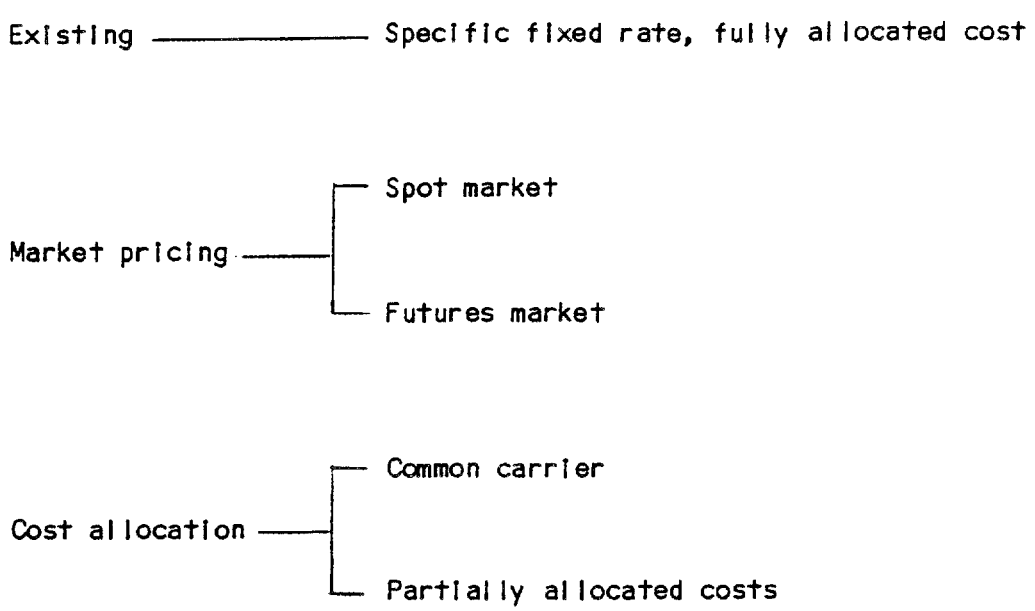
Often the contribution to the peak determines capacity cost allocation. Existing compensation methods and rate forms were evaluated in Section 4.3. Alternatives to this existing compensation methodology can be divided into two categories: (1) market pricing methodologies; and, (2) differing cost allocation methodologies. These categories and the alternatives which fall under these categories are shown in Figure 5.2.

Under the first category, market pricing, are two alternatives: (1) spot market pricing; and, (2) futures market arrangements. Although time varying rates exist, continuously variable wheeling rates or rates that allocate capacity (when capacity limits are reached) by instantaneous changes in rates were not found in existing arrangements. In spot market pricing rates are set so that marginal costs are covered, then, if demand approaches capacity, rates are raised so that capacity is not exceeded. By this method only the most valued uses can afford and use the capacity. Efficiency in the use of the service is therefore achieved. Adequacy is not guaranteed by the pricing method in the short run. If substantial excess capacity exists marginal costs will be low and the capacity costs probably will not be covered. Conversely, capacity is limited, the premium paid to obtain use of the capacity may be substantial and overrecovery of capacity costs may result. In each case adequacy is not achieved. However, two part rates may be used to correct deficits and surpluses of capacity costs.

Fairness is achieved in that no subsidies are occuring. At each point in time each user is paying at least the marginal cost of service. At any point in time, however, especially when capacity is tight along some lines, different prices may be paid depending on the effect a particular customer's load has on the system. For some definitions of fairness, the practice of charging different rates to customers is unfair. As mentioned previously under this type of arrangement, continuously determining prices based on marginal cost may be difficult to achieve. Also prices may have to be raised substantially to curtail demand when capacity is reached. Utilities may object to the widely fluctuating pricing pattern.

Another alternative under the category of market pricing is the nonfirm arrangement with futures markets for the degree of

Figure 5.2 Compensation Methods



firmness. In this situation two prices exist for two services being provided, the actual wheeling services and the reliability of that wheeling service. The two prices cause the best use to be obtained for both services and efficiency is satisfied. Since there are no subsidies being produced, fairness is maintained. As in the previous alternative, however, adequacy and practicality are not assured.

Under differing cost allocation alternatives transmission systems could be organized as a common carrier type of operation similar to oil and gas pipelines. In this arrangement all users of the facilities have equal access to the facilities. The owners of the facilities do not necessarily have priority access. All costs, then, are divided among the users. Interstate common carriers are usually required to price according to the "United formula" which is a variation of the "Atlantic Seaboard formula" previously used to determine prices. In the United formula operating costs are divided equally according to usage. Capacity costs are then divided 75 percent to a user's contribution to the peak and 25 percent to usuage charges. The benefits lie in freer access to the system.

Since off-peak usage does not contribute to marginal capacity costs (an additional unit of power transmitted off-peak does not require that more capacity be installed), charging off-peak users for capacity costs lowers efficiency. Some transactions may not occur because the price is too high. With electric power transmission, as opposed to oil and gas pipelines, usage costs can vary substantially between peak and off-peak. Failure to consider these cost differences also adds to the inefficiency in applying the United formula. Adequacy is achieved if the correct rate of return on invested capital is sufficiently high. Fairness is not obtained since there could be substantial cross subsidies between peak and off-peak users of the transmission system. Since the cost of information needed to implement this alternative is similar to existing arrangements and since the methodology is commonly used for oil and gas pipelines, there probably would be no problems in implementation.

A final alternative under differing cost allocation alternatives which is similar to the previous cost allocation scheme is partially allocated costs. Transmission systems provide other services besides the simple transfer of power.[4] Foremost among them is increase in reliability and voltage stabilization especially to the utility whose service area the lines transect. It has been argued that these other uses should pay a share of the costs of the system. Hence only a certain percentage of the costs are allocated to transmission services.

This is an argument based on equity arguments rather than a cost basis since little costs are probably incurred as a result of these other uses of the transmission system. The system probably does not become more efficient, therefore, due to the reallocation of costs (and probably becomes less efficient since the reallocation would probably be substantial compared to actual cost involved). If the costs incurred due to these other uses are small, little subsidies exists among users and nothing is gained in fairness. Adequacy would not be affected since the same revenues would be recovered. Costs are merely reallocated from one group to another. Determining the amount to reallocate to the other uses will be difficult to determine. If the reallocation is based on the "worth" of the other uses, the "worth" may not have a quantifiable basis. Hence, there may be serious questions as to the practicality of implementing this methodology, especially in having agreement on the amount of cost reallocation is involved.

5.3 Specific Requirements for Service

Specific requirements for service include requirements on entities eligible for service, connections, voltages, and the cost for special equipment. Since tariffs are fairly uncommon in wheeling arrangements (and even then, limitions are placed on eligibility), usually the wheeling arrangements specify that

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4. See Chapter 2

only a certain entity is allowed service. Additionally, those entities are sometimes limited on the service they may obtain (such as the direction of power flows). An alternative to these limitations would be to treat transmission service as common carriers as mentioned previously. Under this arrangement, any entity desiring any type of service will be served if capacity is available (some common carriers had restrictions historically on who they may serve). If capacity is approached, rationing is on a first-come first-served basis (although price could also be used for rationing).

Arbitrarily limiting service can decrease efficiency since the capacity may not be put to its best use. Therefore, if common carrier organization opens up eligibility, efficiency will increase. Since power flows may not be as predictable as when entities are limited there may be a question about practicality when advance planning for flows is needed. Fairness and adequacy are not applicable to these requirements.

5.4 Notice and Response Requirements

Requirements under this category include: the notice by buyer for initial start of service; the response by seller for initial start of service; the scheduling notice for transaction; the notice for interruption of scheduled service; and the notice for permanent termination. In general, notice and response requirements are not formalized in a document but are orally agreed upon by the parties involved. Notice and response requirements are needed to be able to plan for expected power flows. Alternatives to existing practice can either be more restrictive or less restrictive. The more restrictive notice and reponse requirements become, the more probable that some short-term wheeling transactions will not be able to occur. Therefore, improvements would come if the notice and response requirements could be shortened.

In order to take full advantage of spot market pricing short notice requirements are essential. If prices are changing at five-minute increments, utilities must be able to adjust quickly

to avoid unnecessary costs. Implementation of spot market pricing would require computer simulation of the system to determine costs. This same computer simulation would alleviate the need for longer term planning in the system. The effects of any transaction would be known immediately.

Efficiency would be heightened in that the most advantageous transactions, even if extremely short-term, could have the opportunity to gain access to the transmission system. If this occurs, then the system will be put to its best use thereby increasing efficiency. The practicality of implementing such a computerized system is still questionable and further research is needed for implementation, but recent advances in computer systems should enable the system to be implemented.

A common carrier system would also benefit from increased responsiveness to short-term transactions. Since the eligibility type of service would be expanded, various new short-term transactions may be requested. If they could be served through shorter response times then efficiency would be increased.

5.5 Miscellaneous Requirements

Miscellaneous requirements include requirements on the type of power which can be wheeled, special terms and conditions not discussed elsewhere (usually arrangement specific); loss adjustments; and reactive power factors.

5.5.1 Type of Power

Almost half of the arrangements place restrictions on the type of power which can be wheeled. Generally, the restrictions help stabilize the transactions to allow for better planning. An alternative to this restriction is to not specify the type of power which can be wheeled. With increased planning capability under spot market pricing and common carrier systems, the necessity for increasing certainty through having corresponding

wheeling and power arrangements will be decreased. The elimination of these restrictions will increase efficiency in that some transactions may occur which would otherwise be restricted. For example, a utility with a firm wheeling contract may find that alternative sources of power supply may be cheaper than the power from a current supplier. Under some existing arrangements this transaction would not be allowed to occur.

5.5.2 Adjustment for Losses

A majority of wheeling arrangements mention how losses are calculated. Usually they are based on system average losses. Losses vary according to the loads (kW's) on particular transmission lines. Since loads are continually changing, losses are continually changing. Near the capacity limits of a line losses can be substantial.

An alternative to the use of average system losses is to simulate the system and determine the losses between the receiving and delivery point (or points) for the wheeling transaction. This method of determining losses is estimated periodically in the proposed Texas Public Utility Commission wheeling arrangement[5] and by the Bonneville Power Administration. Since losses are so specific to a particular transaction this method gives a more accurate representation of the actual losses involved in a transaction. Losses are a significant part of the marginal cost of a wheeling transaction. An increase in the accuracy of cost will increase efficiency in that the price of the wheeling transaction will more accurately reflect the cost of supplying the wheeling service. For some small transactions the cost of the system simulation may be prohibitively high, and therefore, this method may not be practical in all circumstances.

Another alternative is continuously simulating the system to determine losses. Since losses are continuously variable, this method would produce more accurate information about marginal

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5. This arrangement is discussed in Appendix II.

costs. For spot market pricing continuous simulation would be necessary for the accurate performance of the system. Since at all times price would reflect cost, efficiency is further increased from the previous alternative. Practicality for small isolated transactions, however, becomes more questionable.

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Appendix I: Description and Classification of Existing Wheeling Arrangements

I.1 Introduction

In 1981, a survey was made of wheeling arrangements filed at the Federal Energy Regulatory Commission (FERC), the federal power marketing agencies, the New York Power Authority, and the Texas Public Utility Commission. The survey revealed that at least 1000 wheeling arrangements existed among utilities in the United States. Over 768 arrangements were filed at the FERC and at least 229 were filed at the non-FERC agencies.[1] Usually the arrangements are for specific services between given utilities and are different in format, rates, and services provided. However, there are some common characteristics among the arrangements. This section identifies the major common characteristics, classifies transmission arrangements according to those characteristics, and analyzes the relationship between these characteristics.

The arrangements can be between two utilities (bilateral) arrangements), among more than two utilities (multilateral arrangements), or among all members of a power pool. The arrangement either is specifically limited to particular participants in the arrangement (rate schedule) or is available to any entity satisfying certain criteria (tariff). Each arrangement may specify, among other things, the following:

1. Type of transmission service provided (e.g., firm or nonfirm)

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1. These arrangements were for transmission services which would qualify as wheeling under the definition given in Chapter 2. There are additional arrangements in existance for transmission services that do not meet the Chapter 2 definition.

2. Compensation that a wheeling utility will receive for providing wheeling services(s);

3. Adjustments for transmission losses;

4. Notice requirements (e.g., advance notice that the buyer of wheeling service is required to give a potential seller of wheeling service);

5. Conditions under which a utility can refuse to sell wheeling services (i.e., can refuse to wheel);

6. Voltage levels at which the wheeling utility receives and delivers power; and,

7. Identity of purchasers and sellers of the power to be wheeled.

The information contained in the arrangements surveyed was used to develop a system for classifying wheeling arrangements and is described in this appendix. An overview of the arrangements filed at the agencies covered by the survey will first be presented. Then, the classification scheme will be developed. Finally, a sample of wheeling arrangements will be classified and analyzed.

I.2 Description of Agencies and Arrangements Filed with Those Agencies

Wheeling arrangements are filed at a number of different government agencies, and in some cases are available only from the utilities themselves. Some of the agencies have standardized agreements but the majority of arrangements are dissimilar from one another. This appendix describes the types of arrangements and wheeling services used at these agencies.

Utilities are required to file wheeling agreements at the FERC, the Texas Public Utilities Commission (TPUC), and/or various public power agencies. The agreements filed at FERC usually involve privately owned utilities. The agreements at the TUPC are those involving agreements only between Texas utilities.

There are seven well-known public power agencies in the United States which have wheeling agreements on file. They serve many municipal utilities, rural electric cooperatives, some industrial preference customers, and investor-owned utilities. These organizations are the Tennessee Valley Authority (TVA), the five federal power marketing agencies [the Alaska Power Administration (APA), Bonneville Power Administration (BPA), the Southeastern Power Administration (SEPA), the Southwestern Power Administration (SWPA), and the Western Area Power Administration (WAPA)], and the New York Power Authority (NYPA).

1.2.1 Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission is responsible for approving/determining the rates and other conditions of wheeling services involving the transmission of electric power by jurisdictional utilities in inter-state commerce. A wheeling arrangements may be filed at the FERC as the result of a court ordered settlement, an agency ordered settlement (such as from the Nuclear Regulatory Commission), or certain voluntary agreements among utilities. A survey was conducted of the population of transmission arrangements filed at FERC. Information was obtained on 768 wheeling arrangements which apperared to meet the critieria for wheeling specified in Chapter 2. Initially it was determined that, as of March 11, 1981, there were 1209 separate transmission filings at the FERC. However, not all of these filings could be classified as separate wheeling arrangements. Of the 1209 filings, 261 were certificates of concurrence.[2] There were also 140 arrangements that, although they involve transmission service, did not satisfy the definition of wheeling given in Chapter 2. Moreover, there were 22 arrangements missing from the files and 18

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2. In some wheeling arrangements, more than one party may act as a seller of wheeling services. In such circumstances, Commission regulations permit one party to be designated and authorized to file the agreement on behalf of all the parties. The other parties have the option of filing only a certificate of concurrence, rather than a separate copy of the arrangement. since some utilities may file a separate copy, there may be double counting of arrangements in the survey.

arrangements that did not contain enough information to permit proper classification. The discussion that follows deal only with the 768 separate wheeling arrangements.

A substantial number of the wheeling arrangements do not contain detailed information about the particular transaction which they cover. Also, the arrangements are subject to misinterpretation since they sometimes are scattered throughout a larger document or are not clear in their meaning. A general description can be made about these arrangements, but the reader is cautioned that errors undoubtably exist in the information that will be presented.

As was expected, almost all of the entities supplying wheeling services in arrangements filed at the FERC were investor-owned utilities (94.6 percent). Cooperatives comprised 2 percent of the entities, and municipals, federal, and state agencies or power districts each comprised about 1 percent. Of the entities buying wheeling services 63.5 percent were investor-owned utilities, 20.9 percent were municipals, 9.4 percent were cooperatives, and state agencies or power districts and federal agencies were about 3 percent apiece. Investor-owned utilities were 80.9 percent of the entities selling power in the wheeling arrangements, federal agencies were 6.8 percent, municipals were 5.2 percent, cooperatives were 4 percent, and state agencies or power districts were 3.1 percent. Of the entities buying power, 61.4 were investor-owned utilities, 21.6 percent were municipals, 10 percent were cooperatives, 4.4 percent were federal agencies, and 2.6 percent were state agencies or power districts.

The arrangements were first broken down into two types of arrangements, rate schedules and tariffs. Relatively few tariffs existed, comprising only 2 percent of the total, and almost all of these were wheeling with separate compensation. Of the rate schedules, 89 percent were wheeling with separate compensation and 11 percent were wheeling with nonseparate compensation.

The next breakdown of the arrangements was the form of the arrangements. The forms were: (1) bilateral agreements, which

comprised 70 percent of the arrangements; (2) multilateral agreements, which comprised 25 percent of the arrangements; and, (3) power pool agreements, which comprised 5 percent.

Next, the terms and conditions of the surveyed arrangements were examined. A substantial number of the arrangements, 79 percent, were firm arrangements as opposed to nonfirm arrangements.[3] The compensation method specified for the wheeling service was almost equally divided between a specific rate and a multipart rate formula, 45 and 40 percent respectively. Few arrangements used nonmonetary compensation or specified other types of charges. There were three arrangements that had ratchets[4] as part of the rate formula.

Three general types of notice requirements were contained in the arrangements. Few arrangements specified that the buyer of the service was required to give a specific advance notice to the seller for the start of service or that the seller was required to respond to that request within a certain time, 11 percent and 4 percent respectively. However, 42 percent specified a particular advance notice for termination.

Approximately 38 percent of the arrangements specified a particular method for recovery of power losses due to the wheeling service. The most common method (used in 44 percent of those which specified methods) was that the utility providing the wheeling service would take a certain percent of the power transmitted. Very few arrangements, 3 percent, specified that a particular, absolute amount of power would be taken.

Only in 1.4 percent of the arrangements were conditions placed on the buyer of the power in terms of what the buyer could do with the power. Only 1.4 percent state that the service could be refused if the power were destined for a specified type of

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3. See Appendix II for detailed definitions of firm and nonfirm arrangements.

4. Ratchets are rate forms which raise or lower rates for a specific time period if a certain condition is met.

customer or for resale to other utilities.[5] Restrictions placed on the lines or facilities that could be used for the wheeling service were found in 15 percent of the arrangements. Specific delivery voltages or ranges of voltages were not usually specified.

1.2.2 Summary of Non-FERC Arrangements

Similar to the FERC arrangements, a survey was taken to determine the terms and conditions of the arrangements filed at non-FERC agencies. However, rather than a survey of the population of wheeling arrangements, a sample of wheeling arrangements was surveyed. The sample was chosen to be representative of all types of arrangements filed at the agencies rather than a random sample. A sample was used since many of the numerous arrangements at WAPA and NYPA are close duplicates of one another and no more important information would be obtained, or, as in the case of SEPA and SWPA the arrangements were either on file at FERC or did not satisfy the definition of wheeling as defined in Chapter 2.

In the case of NYPA those arrangements which were not surveyed were percent adder arrangements, each having similar terms and little supporting information. The vast majority of the WAPA arrangements were one of four standard types of arrangements. Each of the arrangements of a standard type were close duplicates of all the other arrangements of that type. The remainder of the arrangements that were not covered by the sample were arrangements from SWPA or SEPA. The SWPA arrangments not included in the sample are those which do not agree with the definition of wheeling in Chapter 2 or are arrangements in which SWPA buys service from other utilities which are required to file the arrangement at FERC. SEPA does not own transmission facilities, therefore all of its arrangements involve the purchase of service by SEPA from other utilities which file the arrangements at FERC.

A breakdown of the sample that was surveyed is given in Table 1. The table lists the agency, the role the agency played in the transaction, the total number of arrangements surveyed from that

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5. Such restrictions have now been declared *per se* unlawful by the FERC. See Gulf States Utilities Co, Docket no. ER76-8161 Order Approving Settlement Subject to Condition (issued October 20, 1978).

Table 1. Survey breakdown by role of non-FERC agency

Utility	# Agency Selling	# Agency Buying & Selling	Total Surveyed	Number on File
1. Alaska Power Administration	3	1	4	6
2. Bonneville Power Administration	69	0	69	+111
3. Southeastern Power Administration	0	0	0	12
4. Southwestern Power Administration	14	3	17	65
5. Western Area Power Administration	68	7	75	?400
6. Power Authority of the State of New York	62	0	62	?100
7. Tennessee Valley Authority	1	0	1	1
8. Texas	1	0	1	1
Totals	218	11	229	*696

*Includes nonwheeling and agency buying.

agency, and finally, the number of arrangements filed at that agency. Approximately 50 percent of all transmission arrangements filed at the non-FERC agencies were covered by the sample. All nonwheeling arrangements (according to the definition of wheeling given in Chapter 2) were then eliminated from the sample. This elimination led to 229 wheeling arrangements.

In the non-FERC wheeling arrangements, federal agencies comprised 53.7 percent of the entities supplying wheeling services, state agencies or power districts comprised 23.5 percent, investor-owned utilities comprised 16.7 percent, cooperatives comprised 5.1 percent, and municipals 1 percent. Of the entities buying wheeling services 30.1 percent were investor-owned utilities, 28.4 percent were municipals, 23.5 percent were federal agencies, 12.5 percent were state agencies or power districts, and 5.3 percent were cooperatives. Approximately 49 percent of the entities selling power in the wheeling arrangements were state agencies or power districts, 42 percent were federal agencies, 5.6 percent were investor-owned utilities, 2 percent were cooperatives, and 1.4 percent were municipals. Of the entities buying power 50 percent were municipals, 20.5 percent were investor-owned utilities, 12.5 percent were state agencies or power districts, 10.7 percent were federal agencies, and 6.25 percent were cooperatives.

Most of the arrangements filed at the agencies were rate schedules as opposed to tariffs. Of the rate schedules, 98 percent were wheeling with separate compensation, as opposed to nonseparate compensation, for the transmission service being provided in a power agreement. Bilateral agreements comprised 94 percent of the arrangements.

Some of the terms and conditions for the arrangements were remarkedly similar to the terms and conditions for the FERC arrangements. For example, 79 percent of the arrangements had provisions for firm service as compared to 79 percent for the FERC arrangements surveyed. The compensation method specified in most of the arrangements was a specific rate (69 percent). Only 20 percent of the arrangements had multipart rate formulas. In the FERC arrangements the arrangements were almost equally divided between these two types of compensation.

Nonmonetary compensation was used in 2 percent of the arrangement and, similar to the FERC arrangments, ratchets were not common (2 arrangements).

Advance notice requirements by the buyer for the start of service or requirements on the amount of time the seller has to respond to the request for service were explicitly stated in few of the arrangements. Notice for service start was contained in only 10 percent of the arrangements, while response requirements were only in 5 percent of the arrangements. Advance notice for termination of the arrangement was more frequent, existing in 45 percent of the arrangements. These percentages are similar to those of the FERC arrangements which were 11 percent, 4 percent, and 42 percent respectively.

The method by which transmission losses would be recovered appeared in almost 84 percent of the agreements. Usually, this took the form of a percentage of power received by the wheeling entity. Of the arrangements that mentioned the method used, 64 percent were of this form. The other method mentioned varied as to how losses would be recovered. Few arrangements specified restrictions as to the voltage at which the buyer could receive power, which lines could be used, or other limitations on transmission facilities (7 percent). Conditions under which the seller could refuse service to the buyer existed in 23 percent of the arrangements. Of these conditions, the most common (34 percent of those that mentioned conditions) was if the buyer of the power were to sell the power to another utility.

Overall the arrangements at the non-FERC agencies are very similar to those filed at FERC. Perhaps the most important similarity is the high percentage of firm arrangements versus nonfirm arrangements and the low number of tariffs that exist. It appears that firms have a tendency toward stable, guaranteed arrangements with respect to transmission service. However, the amount of power transferred under such arrangements probably does not correspond to the number of arrangements. For example, many of the power pool arrangements, although they may only be one arrangement, are nonfirm, have a large number of firms involved, and have a large amount of power transmitted under them. Therefore, nonfirm arrangements may be more important than the numbers of arrangements may indicate.

The following eight subsections present additional information about wheeling arrangements associated with each of the non-FERC entities included in the survey. Some readers may choose to skip these subsections, in as much as they are not neccessary for an understanding of the rest of this appendix.

I.2.2.1 Public Utility Commission of Texas

The Public Utility Commission of Texas (PUCT) has responsibility for all agreements between utilities in Texas which are not subject to FERC regulation, i.e., those which power flows do not cross the state borders of Texas. Power flows do not cross the state borders in the region consisting of the members of the Electric Reliability Council of Texas (ERCOT). Utilities are only required to file the agreements with the PUCT if there is a disagreement between the parties about the agreement. Presently, only one agreement is on file. Recently, the PUCT has detailed the provisions necessary in wheeling agreements which are filed with the PUCT. This section will review these new requirements.

The provisions are applicable to agreements which involve firm power sales. There are two sets of provisions based on whether the amount of power exchanged by the utilities is greater than or less than 25 megawatts. Generally, the charge for the wheeling service for transactions involving more than 25 megawatts is determined by finding the actual cost of the total transmission system based on a cost of service study and multiplying it by the changes in megawatt miles of power flow on the system due to the wheeling service, divided by the total megawatt miles of power flow service provided by the utility. The megawatt miles of power flow are determined by load flow studies at the peak load. For simplification, in cases where the power exchanged by the utilities is less than 25 megawatts, and only one connection exists with other utilities by the buying utility, the buying utility can optionally choose to multiply the annual cost of the total transmission service of the wheeling utility by the megawatts of wheeling service contracted for divided by the megawatt load at system peak of the wheeling utility. However, if the wheeling utility can show by load flow studies that they are impacted by more than 50 megawatts at their boundaries by the sum of all simplified

agreements, they can charge based on the former method. Losses are calculated from loss matricies constructed by ERCOT and are paid in kind.

1.2.2.2 Tennessee Valley Authority

The Tennessee Valley Authority (TVA) is a government agency headquartered in Knoxville, Tennessee. The agency is responsible for flood control, economic development of the region, and power production. The agency's customers are other utilities and large industrial end-users. They do not generally serve residential, commercial or small industrial customers.

TVA has one wheeling arrangement with Big Rivers Electric Power Corporation (a Kentucky Cooperative), Alabama Electric Cooperative, and South Mississippi Electric Power Association. Power is received by TVA from Big Rivers and transmitted to the other parties. The arrangement is for short-term interruptible power and what TVA calls miscellaneous energy. Transmission may be discontinued when:

1. conditions on the TVA system are such that TVA's generating sources, and other sources available to TVA, are inadequate to supply firm power requirements of the TVA system;

2. service interfers with transactions scheduled under contractual arrangements with systems other than Big Rivers, including without limitation, economy interchange transactions;

3. or, service reduces the reliability of the entire TVA system.

TVA can use delivered energy from Big Rivers to meet their firm-power requirements if they are not able to meet them through other means, or they may request Big Rivers to use the power if it is not used by the other companies in the wheeling arrangment.

The rates TVA charges for the wheeling service are 20 cents per week per kilowatt of the maximum aggregate hourly amount of

power scheduled for transmission and 0.22 cents per kilowatt hour for miscellaneous energy scheduled for acceptance. There is also a customer charge of $1,000 per month. Losses are calculated by reducing the amount of power delivered by TVA to the other utilities by 3 percent rounded to the nearest full megawatt. Any special equipment required to complete the power transmission such as additional metering, telemetering, load control, and communications facilities are provided by the utilities involved at no expense to TVA.

1.2.2.3 Alaska Power Administration

The Alaska Power Administration (APA) headquartered in Juneau, Alaska, is responsible for marketing approximately 77 megawatts of hydroelectric power generated from two projects. APA currently has interconnection agreements to buy and sell wholesale power service with five utilities. In addition, APA has five transmission arrangements with utilities that transmit wholesale requirements power to APA's preference customers. APA is a seller of transmission service in three of the arrangements and a purchaser of transmission service in the other two. These power and transmission arrangements are with an investor-owned utility, a municipal system, and three rural electric cooperatives. Each of these utilities except the investor-owned utility are preference customers of APA.

Two types of services are covered in APA's five transmission arrangements. The first type, which is comprised of three arrangements covers nonwheeling transmission services, requires separate compensation for transmission costs incurred by APA in the sale and delivery of wholesale requirements to preference customers directly interconnected to the APA grid. The second type of transmission service is the wheeling of power marketed by APA to a preference customer by a third party. This service, which is covered under one bilateral and one multilateral arrangement, provides preference customers with long-term firm access to hydroelectric generation to meet their wholesale requirements. In addition, the multilateral agreement requires the wheeling agent to provide nonfirm power to APA's preference customer in the event of an unscheduled outage. The terms of this emergency service are specified in a contract between the wheeling agent and the preference customer. The two wheeling

arrangements specify a rate in mills per kilowatt-hour for the wheeling service.

1.2.2.4 Bonneville Power Administration

The Bonneville Power Administration (BPA) headquartered in Portland, Oregon, is responsible for marketing power and energy generated from multi-purpose dams constructed by the Army Corps of Engineers and the Water and Power Resources Service. In addition, BPA markets output from the Hanford Nuclear Project of the Washington Public Power Supply System. BPA provides the primary transmission grid in the Pacific Northwest with 133 interconnections with 19 utilities. BPA serves 161 electric customers, including 116 public systems (municipals, cooperatives, and public utility districts), eight investor-owned utilities, and six federal agencies.

BPA participates in over 100 transmission arrangements as both the wheeling agent and recipient of wheeling services. As a wheeling agent, BPA delivers wholesale power to many municipals, cooperatives, and investor-owned customers that buy from public utility districts (PUD). In addition, BPA makes excess transmission capacity available to investor-owned utilities to provide an interconnection with isolated portions of the investor-owned utility's grid. Bonneville also serves as a wheeling agent for a number of Pacific Northwest utilities holding entitlements in coal-fired and nuclear generating plants, including the Hanford and Trojan nuclear plants, and the Colstrip and Centralia coal-fired plants.

Bonneville sometimes provides an unusual type of wheeling service for industrial customers that it services under power sales agreements requiring BPA to sell and deliver firm and nonfirm power and energy. For example, if BPA is forced to curtail nonfirm energy deliveries to the customer, the customer may request BPA to purchase (for the customer's account) available nonfirm energy to replace the curtailed deliveries. In addition to charging the customers for the cost of the purchased power, BPA also charges the customer for the cost of the nonfirm wheeling service.

BPA also purchases wheeling services as a participant in a number of arrangements providing for the delivery of wholesale firm power and hydroelectric power to its preference customers. Wheeling agents for BPA include municipal utilities, PUDs, and investor-owned utilities. BPA can also serve isolated preference customers using nonwheeling transactions with utilities whose grids lie between BPA's transmission grid and its isolated preference customers. The intervening utility uses its own generating resources to supply the customer's allocation of BPA preference power. In return, BPA uses its own generating resources to supply the intervening utility at a mutually agreed upon time with an amount of power and energy equal to that supplied to the isolated preference customer. BPA is also required to pay the intervening utility for the use of the utility's transmission facilities. The cost of the delivered power and energy and the transmission charges are flowed through by BPA to the preference customer.

In 1981, compensation for wheeling services provided on BPA's transmission system was derived from one of three rate schedules: the Formula Power Transmission (FPT-1) rate schedule, the Use-of-Facilities Transmission (UFT-1) rate schedule, and the Energy Transmission (ET-1) rate schedule.[6] Schedule FPT-1 is a multipart rate that included a Main Grid Charge for use of facilities greater than 115 kV, a Secondary System Charge for use of facilities less than or equal to 115 kV, and an Intertie Charge that applies when an arrangement requires the use of the Pacific Northwest-Pacific Southwest Intertie. The Intertie is a transmission system that consists of an 800 kV DC and two 500 kV AC lines. The Main Grid and Secondary System charges included unit charges per KW for the use of interconnection and delivery terminals and a mileage rate ($0.135/mile for the Main Grid Charge, and $0.036/mile for the Secondary System Charge). Like the mileage rate, the unit charges for the Secondary System are greater than those for the Main Grid.

Schedule UFT-1 covered wheeling services requiring the use of specific portions of BPA's transmission facilities commonly

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6. These schedules have now been superseded by FPT-2, UFT-2, and ET-2.

referred to as the Federal Transmission System. Under this rate, the monthly charge per kilowatt of transmission demand equals one-twelfth the annual cost per kilowatt of the capacity of the facilities specified in a particular arrangement. The annual cost is defined by:

$$\text{Annual cost} = \frac{I \times R}{Ca \times Cf}$$

where

I = Capital cost of facilities specified in the arrangement

R = Capital cost recovery factor for each segment

Ca = Capacity of facility (in kw)

Cf = Capacity factor.

Schedule ET-1 covers BPA's transmission using the excess capacity of the Federal Transmission System of nonfirm energy produced by another utility. Under this rate, the cost of transmission service depends on the specific portions of the Federal Transmission System used to provide the service. For example, transmission service provided on the high-voltage Main Grid is less expensive than transmission over the lower voltage Secondary system or the Pacific Northwest-Pacific Southwest Intertie. The rate ranges from 0.75 mills/kWh (Main Grid delivery) to 1.25 mills/kWh (Intertie delivery). This rate schedule also includes provisions for losses, expressed as percentages, for use of specific portions of the Federal Transmission System.

1.2.2.5 Southeastern Power Administration

The Southeastern Power Administration (SEPA), headquartered in Elberton, Georgia, markets approximately 3,000 mW of capacity generated at 21 reservoir projects constructed and operated by the Army Corps of Engineers. As of September 1979, SEPA sold power and energy to 108 rural electric cooperatives and 80 municipalities in a 10-state region. Other customers include the Tennessee Valley Authority, the South Carolina Public Service Authority, a county power commission, and eight

investor-owned utilities. SEPA has no transmission facilities, and thus provides no wheeling for others. With the exception of certain transmission services provided by the South Carolina Public Service Authority, investor-owned utilities provide all transmission services for SEPA. Currently, SEPA has 12 contracts with these utilities to provide transmission service to preference customers. Each of these 12 arrangements can be classified as third-party wheeling services (i.e., the wheeling utility is not one of SEPA's preference customers) that allow SEPA to deliver long-term firm wholesale requirements to preference customers.

Each of SEPA's 12 transmission arrangements specifies transmission losses as a percentage of power delivered by SEPA to the seller of the transmission service for delivery to SEPA's customers. The loss percentages range from 1 percent to 6 percent. Notice requirements for the termination of transmission service require SEPA to give a wheeling agent a 15-day notice of the termination of the transmission service if a preference customer terminates its power sales agreement with SEPA. If SEPA or a wheeling utility wish unilaterally to terminate transmission service under a specific arrangement, the party wishing to terminate the arrangement must give the other party a 37- to 49-month written notice.

Each of SEPA's 12 transmission arrangements contains a mileage-based transmission service rate that increases the charge per kWh of energy transmitted as the distance to the delivery point increases. Three zones are established from each reservoir project. The first zone covers delivery within a 100 mile radius of the project, the second zone covers delivery from 101 to 150 miles of the project, and the third zone covers any delivery further than 150 miles. Different rates are charged for each zone. The rates are 1.00 mill/kWh for the first zone, 1.75 mills/kWh for the second zone, and 2.5 mills/kWh for the third zone. The majority of the arrangements state the monthly cost of the wheeling service based on the annual amount of energy delivered through the various zones. However, a few of the contracts do not calculate the monthly payment, but simply post the rate per kWh by zone.

The wheeling services covered by the pricing mechanisms used in these arrangements are similar to those in transmission arrangements used by other federal power marketing agencies. However, because SEPA has no transmission facilities or direct interconnections with wheeling agents other than those at the project bus, all of SEPA's power that is allocated to the preference customers must be wheeled by a third party or taken directly from the project bus by a preference customer. (A customer that receives power directly from the project bus receives a 0.06 mills/kWh reduction in the wholesale rate for power and energy.) Therefore, wheeling by two or more utilities is sometimes required to deliver power to preference customers. For example, to deliver power to preference customers located in the area served by Carolina Power and Light Company (CP&L), SEPA must pay wheeling charges to both Virginia Electric Power Company and CP&L.

1.2.2.6 Southwestern Power Administration

The Southwestern Power Administration (SWPA), headquartered in Tulsa, Oklahoma, is responsible for the sale of 1,900 mW of power generated from 17 hydroelectric facilities located in four southwestern states. SWPA is currently a participant in 65 interconnection agreements involving the sale and transmission of federal power and the transmission of nonfederal power. These arrangements, both bilateral and multilateral, involve investor-owned utilities, municipals, rural electric cooperatives, a state agency, a federation of generating and transmission cooperatives, and the Western Area Power Administration (WAPA).

SWPA recovers the cost of its wheeling and nonwheeling services through its wholesale rates to preference customers and wheeling Rate Schedule TDC-2. Under its power sales contracts with preference customers, SWPA recovers nonwheeling transmission costs via a separate transmission charge included in its wholesale power rate schedules for full or partial wholesale requirements, hydroelectric peaking power, and short-term interruptible power. Each customer's monthly bill includes a charge equivalent to one-twelfth of the customer's share of SWPA's estimated annual cost of delivering power and energy to the customer. The estimated cost is derived in a repayment

study that examines investment costs, administrative expenses, and operating and maintenance expenses.

The Flood Control Act of 1944 requires SWPA to make available all excess transmission capacity to wheel nonfederal power and energy. All nonfederal power and energy must be wheeled according to schedules set by SWPA. SWPA recovers the cost of its wheeling service under Rate Schedule TDC-2, which is a postage stamp rate approved by the Federal Energy Regulatory Commission. This schedule specifies charges based on the specific facilities used in performing the contracted service. Rate Schedule TDC-2 differentiates charges by voltage level of transmission lines and the level of transformation service (the amount of voltage step-down required). Under the current schedule, SWPA provides interruptible service at a 5 percent reduction from the firm service rate. Currently, 13 utilities and one state agency purchase wheeling services from SWPA. Of these 14 customers receiving service under Rate Schedule TDC-2, most are municipal utilities in SWPA's Missouri service area. Specifically, through a series of one year bilateral arrangements, SWPA wheels nonfirm secondary energy that is generated by coal-fired units owned and operated by Springfield City Utilities and sold to other municipalities.

SWPA also purchases three basic types of wheeling services from other utility systems. Under certain wheeling arrangements, the wheeling agent delivers SWPA power to preference customers. In other cases, the wheeling agent serves either as a link between an isolated loop of SWPA's transmission grid and SWPA's main grid or as a link between isolated generating facilities operated by SWPA. In addition, SWPA has entered into an arrangement with the Western Power Administration for the sale and purchase of exchange energy. Because there is no direct interconnection between the two marketing agencies, SWPA has contracted with Associated Electric Cooperative, Inc., to provide wheeling services necessary to complete exchange energy transactions with WAPA. This service is covered under a much broader arrangement between SWPA and Associated.

SWPA's contract with Associated Electric Cooperative is unique in that, under this multiple service arrangement, both parties purchase transmission service from each other. Moreover,

compensation for services is typically reflected through billing credits to Associated for services rendered to SWPA. For example, Associated provides wheeling services to some of SWPA's preference customers and between SWPA and WAPA to provide for the sale of exchange energy. In addition, Associated performs operation and maintenance services on isolated portions of SWPA's transmission grid. In return, SWPA provides wheeling services to some of Associated's customers. Charges for most of these services are netted out of Associated's monthly bills for energy. However, some wheeling services, such as the SWPA-WAPA interchange, are provided by Associated at no cost up to specified levels of service. Beyond the designated limit, rate schedules specified in the SWPA-Associated contract are used to recover transmission cost. Furthermore, Associated provides, at no cost to SWPA, all transmission facilities needed to receive power and energy from three isolated hydro facilities.

1.2.2.7 Western Area Power Administration

The Western Area Power Administration (WAPA), headquartered in Golden, Colorado, operates in a service area extending through 15 western states. WAPA serves 464 customers, including private utilities, public utility districts, municipal utilities, rural electric cooperatives, irrigation districts, and federal and state agencies. WAPA markets power from 46 multipurpose hydro facilities built and operated by the Army Corps of Engineers and the Water Power Resource Service. In addition, WAPA is responsible for marketing the United States' entitlement from the coal-fired Navajo project. The generating capacity made available to WAPA from these generating resources in 1980 was 8,217 mW.

Four types of contractual arrangements account for the majority of transmission services either purchased or sold by WAPA. These arrangements are classified as interconnection agreements, electric and transmission service agreements, nonfirm transmission agreements, and the Navajo project contracts.

Through a series of interconnection agreements with investor-owned utilities and generation and transmission (G&T) cooperatives throughout its service area, WAPA purchases and sells transmission service. Participants in these arrangements

wheel full- or partial-requirements services to WAPA's preference customers interconnected to their systems. Compensation is generally 1 mill/kWh for all scheduled transmission of energy. Transmission losses are WAPA's responsibility. That is, WAPA is required to deliver the contracted amount of power and energy plus an additional percentage (usually 7 percent more) to cover transmission losses. This means WAPA has to generate or acquire additional energy above what is received or delivered by WAPA.

These contracts also require WAPA each year to provide the wheeling agent with four-year estimates of the load to be served at each preference customer's established delivery points. The wheeling agents then have 90 days to tell WAPA whether they have the ability to provide the wheeling services requested by WAPA.

These contracts also cover firm transmission services provided by WAPA for investor-owned utilities or G&T cooperatives. The function of these wheeling services by WAPA is either to interconnect isolated portions of an investor-owned utility's or G&T's transmission system or to wheel power and energy purchased or sold by the investor-owned utility or G&T through sales agreements with other utilities. WAPA generally receives 1 mill/kWh with a percentage adjustment for losses for providing these firm transmission services.

WAPA does not collect wheeling charges from preference customers directly interconnected with the transmission system of the project from which the customer's wholesale requirements are generated. WAPA markets power from four projects, each of which has its transmission system. These projects are the Central Valley Project in California, Parker-Davis Project in Arizona and Nevada, the Colorado River Storage Project in Colorado and Wyoming, and the Pick-Sloan Missouri Basin Project which is located in Montana, Nebraska, and the Dakotas. However, preference customers who are not directly interconnected with the transmission system of the project from which they receive an entitlement are required to pay transmission charges. For example, much of the power and energy generated in the Colorado River Storage Project (CRSP) is delivered to preference customers interconnected with the Parker-Davis Systems (P-D), which is not interconnected with the CRSP transmission system.

The power and energy is wheeled from CRSP to the P-D system by either Arizona Public Service Company or the Salt River Project Agricultural and Improvement Power District. The preference customer pays a wheeling charge to WAPA equal to 1 mill/kWh for energy wheeled over the CRSP transmission system. In addition, either Arizona Public Service or the Salt River project is allowed to deliver to the customer only 96 percent of the customer's CRSP entitlement to reflect 4 percent wheeling losses. No monetary wheeling charge is levied by either of these two wheeling agents.

If sufficient transmission capacity is available, WAPA will provide firm and nonfirm transmission services to other utilities over the transmission systems of the various projects or their portion of the Pacific Northwest-Pacific Southwest Intertie.

Tariffs for firm and nonfirm wheeling services provided for non-preference customers are in effect only on the P-D system. For example, the firm service rate PD-T2 is $3.67/kW-month, while the nonfirm service rate PD-T3 is 1.3 mills/kWh for all kWh scheduled. Charges for firm and nonfirm wheeling services provided on the other portions of WAPA's transmission grid are negotiated by the parties involved. These rates range from 1 mill/kWh for firm and nonfirm services on some systems to $5.30/kW-year for firm service on other systems. Loss adjustments are added to the cost of all wheeling services. Specific loss adjustment factors are used for wheeling transactions requiring the use of the Intertie system (3 percent) and for all of the projects' transmission systems except the Central Valley Project. For example, a four percent loss adjustment is applied to all transactions requiring the use of the Parker-Davis Project transmission facilities.

WAPA is also a participant in the Western Systems Coordinating Council (WSCC) hourly economy energy brokering system, which involves a series of bilateral interchange and transmission service agreements with G&T cooperatives and several southwestern investor-owned utilities. These transactions require the supply of nonfirm transmission services by the participating utilities.

I.2.2.8 New York Power Authority

The New York Power Authority (NYPA), headquartered in New York City, generates and markets power and energy from hydroelectric projects, nuclear and fossil-fuel plants. As of January 1, 1979, these projects had a combined generating capacity of 6,740 mW. NYPA serves 151 wholesale customers and participates in approximately 100 transmission arrangements with investor-owned utilities, municipalities, rural electric cooperatives, industrial customers, the Metropolitan Transit Authority in New York City, and one neighboring state agency.

The majority of NYPA's transmission arrangements involve the sale and delivery of baseload nuclear and hydro power and energy as wholesale requirements power for municipalities and rural electric cooperatives. Most of these customers are distribution systems with no transmission interconnections with NYPA. To deliver allocations to these customers, NYPA has entered into power sales and transmission (wheeling) contracts with investor-owned utilities. Specific wheeling charges are made by each company and paid by NYPA. The wheeling charges are recovered via a separately stated transmission charge in NYPA's power sales agreement with the preference customer. Most of these wheeling services are provided by utilities located in the vicinity of NYPA's Niagara and St. Lawrence hydro facilities in New York. However, NYPA's service to out-of-state preference customers and to customers on Long Island and some New York customers requires the purchase of wheeling services supplied by other utilities. In addition to the wheeling charges of the investor-owned utilities, NYPA charges preference customers for transmission from the power station to the point of interconnection with the investor-owned utility acting as the wheeling agent.

NYPA also sells wholesale firm power to 15 industrial customers interconnected with NYPA's transmission grid. Power sold to all but three industrial customers is generated at the NYPA's Fitzpatrick Nuclear Plant. Industrial customers located in the St. Lawrence and Niagara service areas are assessed charges similar to nonindustrial preference customer, i.e., a transmission charge and a wheeling charge. (However, customers in the Albany area pay only wheeling charges for services

purchased by the Authority from an investor-owned utility.) NYPA is required by federal law to suppy 445 mW of firm power to Niagara Mohawk Power Corporation to replace power previously generated at two company-owned hydro facilities. The power is resold at NYPA's wholesale firm power rate plus a transmission charge.

NYPA purchases from Hydro-Quebec in Canada for resale to seven major investor-owned utilities in New York and to two preference customers on Long Island. The power is resold as economy energy, short- and long-term unit contracts, and short-term firm energy for fossil-fuel displacement or water storage. NYPA provides transmission service to a point of interconnection with Niagara-Mohawk Power Corporation for 1 mill/kWh. Customers must make their own arrangements for delivery beyond this point.

1.3 Classification System

A wheeling arrangement (or contract) is an agreement between two or more utilities in which one or more of the utilities agrees to wheel power under terms and conditions specified in the arrangement. The arrangements discussed in the previous section can be classified into specific categories based on these terms and conditions. This section develops categories based upon the most important characteristics of the terms and conditions of the arrangements.

The terms and conditions of a wheeling arrangement generally reflect cost, operating, and market factors[7] specific to the utilities covered by the arrangements. For example, a utility may have interconnection agreements with five other utilities, and each agreement may include an arrangement under which the utility agrees to provide the same type of wheeling service for each of the other five utilities. However, the utility may charge each of the five utilities a different price for the wheeling service to reflect the use of different transmission facilities, different percentages of transmission losses

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7. Market factors refer to the condition of the market for power interchanges in an area. For example, are numerous firms involved in fairly large power sales?

associated with serving each utility, power factor adjustments that vary by utility, or a number of other factors that may create differences in the cost of providing the wheeling service.

Although a wheeling arrangement tends to reflect factors specific to the utilities that it covers, most arrangements can be classified by two major characteristics. These characteristics are the:

- 1. Right of the wheeling utility to interrupt or curtail the wheeling service, and

- 2. Method used to compensate the wheeling utility.

Each characteristic is discussed below.

1.3.1 Interruption Rights

A buyer of wheeling service buys either firm or nonfirm service. Firm wheeling service implies that the buyer's right of uninterrupted service by the wheeling utility's transmission system is guaranteed except under limited conditions (e.g., an operating emergency in which the wheeling utility's transmission system cannot carry the wheeling load without reducing the transmission system's reliability to an unacceptable level). The conditions under which firm wheeling service can be interrupted are usually delineated in the wheeling arrangement.

Nonfirm (or interruptible) wheeling service implies that the buyer's right of uninterrupted service by the wheeling utility's transmission system is restricted. These restrictions may be delineated in the wheeling arrangement, in which case the wheeling service may be called conditionally nonfirm or conditionally interruptible service. If the access restrictions are not delineated in the arrangement (i.e., the restrictions or interruptions are at the sole discretion of the wheeling utility), the wheeling service can be said to be unconditionally interruptible or unconditionally nonfirm service.

1.3.2 Compensation Methods

The buyer of wheeling services may be either the seller or buyer of the electricity that is wheeled.[8] The wheeling arrangement usually specifies the compensation to which the wheeling utility is entitled. Compensation is usually determined using one of four major methods:

- 1. A <u>specified fixed rate</u> a wheeling utility receives for providing wheeling services over a specified time period (e.g., an annual or monthly charge) or for each unit of wheeling service provided (e.g., an annual or monthly charge) or for each unit of wheeling service provided (e.g., $4.20/kW per year or 1 mill/kWh). When these rates are not based on mileage they are sometimes called postage stamp rates.

- 2. A <u>formula</u> that specifies either charges for the use of specific facilities and units of wheeling service provided or procedures to be used to derive wheeling charges at the time the wheeling service is provided.

- 3. A <u>split-savings procedure</u> that provides the wheeling utility with a share of the savings created by a power and/or energy transaction. The wheeling utility's share (or split) of the savings is typically one-third or less of the total savings. The method is usually applied to nonfirm energy transaction and to short-term, nonfirm capacity and energy transactions in which the incremental and decremental costs of the utilities participating in the transaction are used in pricing the power and/or energy.

- 4. An agreement between the utilities covered by a wheeling arrangement to repay wheeling services in-kind within a specified time period. For example, if Utility A wheels

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8. Although either the buyer or seller of the wheeled electricity may be the buyer of the wheeling service, and may be the utility that compensates the wheeling utility, the cost of the wheeling service is usually borne completely by one of the utilities participating in the power and/or energy transaction. Responsibility for wheeling costs in a power and/or energy transaction is normaly spelled out in the interconnection agreement between the utilities.

100 mWh for Utility B, Utility B pays no monetary wheeling charges, but instead agrees to wheel 100 mWh for Utility A at a later date. This type of arrangement is commonly referred to as a banking or reciprocal arrangement.[9]

The types of costs for which a wheeling utility should be compensated were discussed in Chapter 2. Of the four compensation methods described above that are used to recover wheeling costs, only specified fixed rates (the first compensation method discussed) state the exact charges for the wheeling service purchased.[10] These charges may be stated in a number of ways using alternative rate forms and their definitions are given in Table 2.

In contrast to wheeling rates determined by the specified fixed rate compensation method, rates determined by the other compensation methods depend on the specific agreement that is reached between the wheeling utility and the buyer of the wheeling service. For example, a multipart formula may specify the factors that will be used to compute charges provided for wheeling services over a given time period (e.g., a month) and the steps for computing the charges. Factors that are often included in a multipart formula are variable O&M transmission-related expenses, embedded costs of specific transmission facilities, capital recovery factors for transmission facilities, loss adjustment factors, and procedures for estimating the incremental generation costs of making up transmission losses. Billings for a wheeling service are then based on the application of the formula using those factors that

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9. Another compensation method that has been used extensively by many wheeling utilities is the percentage adder pricing method. Under this method, the wheeling utility's compensation is based on a percentage of the price of the power and/or energy transaction that is wheeled. Because of the restrictions placed by the Federal Energy Regulatory Commission (FERC) on the use of percentage adders (FERC Order No. 84 and Order No. 84-A, Docket No. RM79-29), percentage adders were not included in the classification of wheeling arrangements.

10. Each method, however, may explicitly state adjustments for wheeling losses and inadequate power factors.

Table 2. Specific fixed rate forms

Rate Form	Definition
Annual Charge	A lump-sum payment made each year by the buyer to the seller of wheeling services. The amount is stated on a $/year basis, and is usually negotiated by the buyer and seller of wheeling services in a manner not specified in the wheeling arrangment. It does not depend on the amount of actual power or energy wheeled, but may depend on the amount contracted to be wheeled.
Monthly Charge	A lump-sum payment made each month by the buyer to the seller of wheeling services. The amount is stated in a $/month basis, and is usually negotiated by the buyer and seller of wheeling services in a manner not specified in the wheeling arrangement. It does not depend on the amount of actual power or energy wheeled, but may depend on the amount contracted to be wheeled.
One-part	A charge per kWh or kW of wheeling service provided in a given time period. A one-part rate may be stated in terms of $/kWh; or $/kW per day, month, or year (e.g., $/kW-month).
Two-part	A charge per kWh and kW of wheeling service provided in a given time period. A two-part rate may be stated in terms of $/kWh plus $/kW-month.
Mileage	A one- or two-part wheeling rate that adjusts the unit charges by distance. A one-part rate may be stated in terms of $/kW or $/kWh per mile (e.g., $/kWh-mile), while a two-part rate may be stated in terms of $/kW or $/kWh per mile plus a capacity charge in a given time period (e.g., $/kW-year).
Declining Block	A rate with 2 or more kW or kWh blocks in which the price charged in each block is less than the price charged in the preceding block.
Time-of-day	A rate with prices per unit of wheeling service that vary by the time of day during which the wheeling service is provided.

the buyer and seller of the service have agreed should be reflected in the wheeling utility's compensation. This means that not all factors specified in a multipart formula are always used in calculating each utility's payments for a specific wheeling service. For example, if no wheeling takes place during peak periods the capital recovery factor may not be used.

The split-savings pricing method is not directly related to the cost of providing the wheeling service. The price reflects the differential between the cost of the buyer and seller of the power to produce the power and/or energy. In a banking arrangement, costs created by wheeling transactions can be recovered without direct cash payments for wheeling services.

1.3.3 Categories

The final categories developed are shown in Figure 1. Also shown are the linkages between the categories. Many of the branches are expected to be empty. For example, split savings compensation methods are usually associated with nonfirm arrangements.

1.4 Classification of Wheeling Arrangements

In order to determine whether there is any consistant pattern between the different categories, a sample of the arrangements surveyed was classified according to the categories developed in the previous section. A sample was used since many of the arrangements either did not specify (or did not clearly specify) important information, accurate classification required a more detailed analysis of the arrangements than was possible in the initial survey.

The detailed analysis involved use of secondary sources to obtain information, if the arrangements did not specify the particular terms and conditions used in the classification scheme. For example, few arrangements specified the duration of service or the cost basis for the determination of rates. Therefore, the utility had to be contacted or other filings examined (such as the corresponding power agreement or supporting documentation for the cost of service).

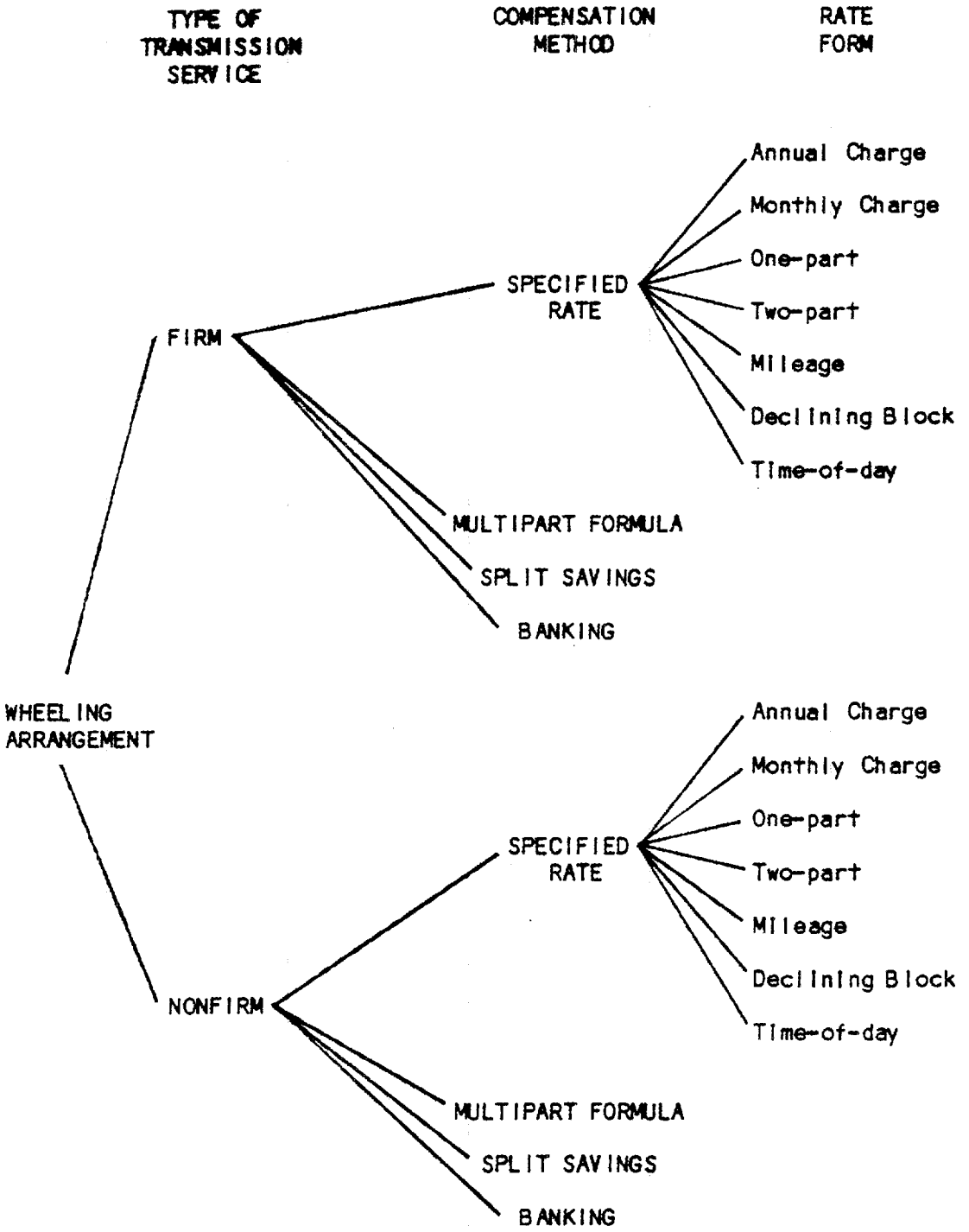

Fig. 1. Classification categories

A random sample was selected, then, from all FERC arrangements surveyed. Due to changes in the definition of wheeling, the sample contains some nonwheeling transmission arrangements. In the FERC population approximately 10 percent were nonwheeling transmission arrangements. In addition, arrangements which had formula compensation methods were eliminated. It was thought that the complexity involved in the arrangements would not enable classification. This led to 173 FERC arrangements in the sample or 20 percent of the FERC arrangements. Since there were only 288 nonFERC arrangements, all arrangments were sampled for potential inclusion in the classification. The same problem as in the FERC sample exists with respect to nonwheeling arrangements. In the entire nonFERC arrangements examined, 16 percent were nonwheeling. Also, as in the FERC arrangements, arrangements with formula compensation methods were eliminated. This produced 158 arrangements or 64 percent of the nonFERC arrangements. As a means of simplifying the following discussion, the 173 arrangements filed at FERC will be called the FERC subsample, and the 158 arrangements filed elsewhere will be called the nonFERC subsamples.

The classification of the transmission arrangements included in the sample of 331 agreements was performed in three steps. Specifically, the sample was sorted by:

1. Utility classification. The sample was divided into the FERC and nonFERC subsamples. This subsample classification was performed to see whether any differences exist between the transmission arrangements filed by utilities at FERC and those utility filings at nonFERC organizations.

2. Type of transmission service. The transmission arrangements in each subsample were sorted by firm and nonfirm transmission service.

3. Compensation method and transmission rate form. The final sorting of the arrangements was performed using three of the four compensation methods and the rate forms discussed earlier.

Some of the arrangements covered more than one type of transaction. Therefore, the total number of different types of arrangements that were classified is 376. The results of the first two steps in this classification procedure produced the results shown in Table 3.

Approximately 73 percent of the transmission services covered in the sampled transmission arrangements were firm services, while 27 percent of the services were nonfirm. Within the subsamples, there appears to be a more even distribution between firm and nonfirm transmission services in the non-FERC subsample than in the FERC subsample.[11] More specifically, about 66 percent of the transmission services in the non-FERC were firm, and 34 percent were nonfirm; while 79 percent and 21 percent of the services covered in the FERC subsample were firm and nonfirm, respectively. A possible explanation for the apparently greater tendency to provide firm transmission services in the FERC arrangements is a difference in the predominant types of power and energy transactions that are transmitted. As shown in Table 4, 56 percent of all transmission services offered in the arrangements included in the FERC subsample were firm transmission services to transmit wholesale requirements power and entitlements. On the other hand, only 36.7 percent of the firm and nonfirm transmission services covered in the non-FERC subsample were firm transmission services to transmit the same two types of power and energy transactions. Wholesale requirements power and entitlements are two major ways in which utilities meet their firm load requirements. Therefore, it seems reasonable that the higher the ratio of a utility's transmission services for wholesale requirements power and entitlements to the total transmission services offered by the utility, the higher the ratio of the utility's firm transmission services to its total transmission services.

More detailed discussions of the transmission arrangements included in each subsample are presented below.

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11. For all wheeling arrangements, though, the percentage of firm and nonfirm arrangements were the same for FERC and nonFERC arrangments.

Table 3. Type of transmission service

	Transmission Service		
Subsample	Firm	Nonfirm	Total
FERC	158	42	200
Non-FERC	115	61	176
Total	273	103	376

Table 4. Power and Energy Transactions

	Power and Energy Transactions (%)		
Subsample	Wholesale Requirements and Entitlements	All Other	Total
FERC	56.0	44.0	100.0
Non-FERC	36.7	63.3	100.0
Total	46.9	53.1	100.0

1.4.1 FERC Subsample

Completion of the three-step classification procedure for the transmission arrangements in the FERC subsample produced the results shown in Table 5 for firm transmission services and nonfirm transmission services. A casual inspection of Table 5 indicates that:

- Four types of transmission rates--annual and monthly charges, one-part rates, and mileage rates--are used most often to compensate the transmission utility.

- Within a particular specific fixed rate form, there is a wide range of prices applicable to a specific transmission service. For example, in one-part rates the prices per kWh for firm transmission range from 0.225 mills/kWh to 26.14 mills/kWh.

Moreover, it appears that utilities offering <u>firm</u> transmission services with a one-part rate are equally likely to use a mills/kWh charge, a $/kW-year charge, or a $/kW-month charge. On the other hand, all but two of the 39 one-part rates for <u>nonfirm</u> transmission services are stated on a mills/kWh basis.

The concentration of the FERC subsample transmission rates in the compensation methods/specific fixed rate forms mentioned above is more clearly shown in Table 6. One-part rates were used in almost 75 percent of the transmission services covered in the sampled arrangements.

The FERC subsample arrangements were also examined to determine how transmission utilities were compensated for transmission losses. This examination revealed that only 25 percent of the transmission services covered in the arrangements included loss-adjustment factors stated in a rate schedule (see Table 7). Approximately 80 percent of the services incorporating loss-adjustment factors were for firm transmission services. In the sample, as shown in Table 7, most utilities either ignore transmission losses or else incorporated the cost of estimated losses in developing the rates stated in the rate schedules that were sampled.

Table 5. Type of transmission service, compensation methods/specific fixed rate form, and rates of arrangements filed with FERC

Type of Transmission Service	Compensation Method/ Specific Fixed Rate Form	Range of Transmission Rates	Frequency
Firm	Annual charge	$34,300/year--$475.000/year	5
Firm	Monthly charge	$132.50/month--$129,959/month	15
Firm	One-part	0.225 mills/kWh--26.14 mills/kWh	47
		$2.70/kW-year--$23.67/kW-year	24[a]
		$0.09/kW-month--$1.20/kW-month	34[b, c]
		$0.20/kW-day	2
Firm	Two-part	$0.50/kW-month plus 1 mill/kWh in excess of 500 kWh/month	1
Firm	Mileage	$0.03/kW-mile/year	5
		$0.03/kW-mile/year plus $1.02/ kW-year	23
Firm	Declining-block	1.9000 mills/kWh for first 150,000 kWh/month 0.7125 mills/kWh in excess of 150.000 kWh/month	1
Firm	Time-of-day	Peak period--$0.0313/kWh Shoulder period--$0.0239/kWh Off-peak period--$0.0207/kWh	1
Firm	Banking		1
SUBTOTAL			158

[a] Includes two contracts with rates differentiated by voltage level of service delivery.

[b] Includes one contract with a rate differentiated by voltage level of service delivery.

[c] Includes eight contracts with rates differentiated by voltage level of service delivery.

Table 5. Type of transmission service, compensation methods/ specific fixed rate form, and rates of arrangements filed with FERC (continued)

Type of Transmission Service	Compensation Methods/ Specific Fixed Rate Form	Range of Trans. Rates	Frequency
Non Firm	One-part	0.25 mills/kWh--3.20 mills/kWh	37[d]
		14.64/kw-year	1
		0.20/kw-day	1
Non Firm	Monthly charge	$420/month	2
Non Firm	Split-savings	One-third of total savings	1
SUBTOTAL			42
TOTAL			200

[d]Includes seven contracts with rates differentiated by voltage level of service delivery.

Table 6. Compensation methods/specific fixed rate forms for firm and nonfirm transmission services filed with FERC.

Compensation Method/ Specific Fixed Rate Form	Transmission Service: Firm	Nonfirm	Total
Annual charge	5	0	5
Monthly charge	15	2	17
One-part	106	39	145
Two-part	1	0	1
Mileage	28	0	28
Declining-block	1	0	1
Time-of-day	1	0	1
Split-savings	0	1	1
Banking	1	42	1
TOTAL	158	42	200

Table 7. Loss-adjustment factors: FERC subsample

Firm Transmission Service			Nonfirm Transmission Service			
Percentage of power received by wheeling utility	Amount of power received by wheeling utility	Other[a]	Percentage of power received by wheeling utility	Amount of power received by wheeling utility	Other[a]	Total
30	2	9	10	0	0	51

[a] Represents percentage loss-adjustment factors that are unspecified in the wheeling arrangement.

1.4.2 NonFERC Subsample

The results of the three-step classification procedure for the nonFERC subsample are shown in Table 8 for firm transmission services and nonfirm transmission services. In contrast to the FERC subsample, the non-FERC subsample of transmission arrangements included a number of tariffs and rate schedules with one-part rates. The non-FERC subsample rates also appear to be lower on average than the FERC subsample rates for the same type of transmission service. In addition, unlike the FERC subsample one-part rates, the non-FERC subsample one-part rates are almost always stated on a mills/kWh basis.

The prevalent use of one-part rates in the non-FERC subsample transmission arrangements is shown in Table 9. Approximately 63 percent of the firm and nonfirm rates are one-part rates (includes rate schedules and tariffs). Almost 24 percent of the rates are incorporated in tariffs. However, tariffs are used much more with nonfirm transmission services (almost 48 percent of the nonfirm subsample) than with firm transmission services (only 11 percent of the firm subsample).

The much higher use of tariffs by the non-FERC relative to the FERC subsample cannot be explained by the data and information provided in the sampled rate schedules and tariffs. Interviews with officials from the non-FERC indicate that these groups try to use tariffs whenever possible, and that efforts to gain wider use of such tariffs will continue. Two reasons given by these officials for this attitude are the greater administrative ease afforded by tariffs and the general willingness of these groups to transmit power as long as they have sufficient transmission capacity available.

Table 8. Type of transmission service, compensation methods/ specific-fixed rate form, and rates of arrangements filed with non-FERC agencies

Type of transmission service	Compensation method/specific fixed rate form	Range of transmission rates	Frequency
Firm	Monthly charge	\$600/month--\$55,020/month	12
Firm	One-part (T)[a]	\$0.25/kW-month--\$0.55/kW-month	13[b, f]
Firm	One-part (RS)[c]	\$0.25 mills/kWh--2.25 mills/kWh	49
		\$4.46/kW-year--\$8.62/kW-year	7[g]
		\$0.0015/kW-month--\$2.70/kW-month	25[d]
Firm	Two-part	1.05 mills/kWh plus \$0.25/kW-month	5
		1.0 mill/kWh plus \$0.00-\$0.22/kW-month	1[b]
Firm	Mileage	1 mill/kWh--2.5 mills/kWh	3[e]
			45
TOTAL			115

[a]T = Tariff.

[b]Demand charge differentiated by voltage level of service delivery in 11 contracts.

[c]RS = Rate schedule.

[d]Includes four contract with a rate differentiated by voltage level of service delivery.

[e]Includes one contract with a three-part mileage rate (100 miles, 101-150 miles, and greater than 150 miles) and two contracts with rates based on zones through which power is wheeled.

[f]Includes two contracts with rates differentiated by substation delivery points.

[g]Includes two contracts with annual escalation clause.

Table 8. Type of transmission service, compensation methods/ specific-fixed rate form, and rates of arrangements filed with non-FERC agencies (continued)

Type of transmission service	Compensation method/specific fixed rate form	Range of transmission rates	Frequency
Nonfirm	One-part (RS)[d]	0.3 mills/kWh--2.93 mills/kWh	30[b]
Nonfirm	One-part (T)[c]	$0.427/kW-month $0.75 mills/kWh--2.0 mills/kWh	1 29[a]
Nonfirm	Two-part	1.05 mills/kWh plus $0.25/kW-month	1
SUBTOTAL			61
TOTAL			176

[a]Includes 14 contracts with a rate that incorporates loss adjustmnets and energy charge differentials by voltage level of service delivery. Also includes one contract with an unspecified charge for use of substation facilities.

[b]Includes two contracts with rates incorporating unspecified charges for the use of substation facilities, one contract incorporating a charge of 0.05 mills/kWh for the use of substation facilities, and one contract incorporating a charge of $9.95/month for incremental dispatching costs.

[c]T = TARIFF.

[d]RS = Rate schedule.

Table 9. Rates for firm and nonfirm transmission services: non-FERC subsample

Compensation method/ specific fixed rate form	Transmission service		
	Firm	Nonfirm	Total
Annual charge	0	0	0
Monthly charge	12	0	12
One-part (Tariff)	13	29	42
One-part (Rate Schedule)	81	31	112
Two-part	6	1	7
Mileage	3	0	3
Declining-block	0	0	0
Time-of-day	0	0	0
TOTAL	115	61	176

Appendix II

Detailed Examination of Wheeling Arrangements

II.1 Introduction

This appendix examines a sample of 52 wheeling arrangements in detail to determine their terms and conditions for service, to state the utilities' rationale for these particular terms and conditions, and to evaluate the arrangements based on the four regulatory goals:

1. achievement of the revenue requirement,

2. efficient use,

3. equity or fair cost apportionment, and

4. practicality and feasibility.

This discussion summarizes the range of issues that have been addressed by wheeling arrangements in order to highlight how wheeling services are provided in practice. The evaluation of the arrangements based on four regulatory goals allows one to judge how well the wheeling arrangements have been designed to correspond with the objectives of public policy. These goals are not always mutually exclusive nor are they necessarily consistent with one another, as the discussions will demonstrate.

The first criterion for evaluation, the revenue requirement goal, deals with whether the utility is able to recover its transmission costs in providing wheeling services to another party. The utility would have no incentive to provide wheeling services and maintain or add transmission facilities unless the revenue requirement is met.

The goal of efficient use is to promote maximum use of a wheeling utility's transmission system within established reliability rules. When the use of the system is maximized under an efficient compensation scheme, the wheeling utility will recover its transmission-related revenue requirement, and the potential aggregate reduction in the operating costs of the utilities purchasing wheeling services will be maximized.

Equity or fair cost apportionment in pricing structures is desired so that one group is not unduly favored at the expense of another. In terms of wheeling services, the common assumption is that fairness means equality. That is, the utility which is buying wheeling services should pay the identifiable cost that it imposes on the system and a uniform share of common cost.

The final goal to be used in the criteria for evaluation is that of practicality and feasibility. This goal may justify a particular term or condition of a wheeling arrangement, although other goals are not met. These four regulatory goals are discussed in depth in Chapter 3.

The terms and conditions of wheeling arrangements which are to be addressed can be categorized into six general areas:

1. type of transmission service available;

2. compensation methods and rate forms;

3. billing determinants;

4. specific requirements for service;

5. notice and response requirements; and,

6. other miscellaneous requirements.

This appendix includes a description of each of these terms and conditions, a discussion of the rationale for their implementation, and an evaluation of the consequences of their use. The sections on the utilities' rationale explain some of the background information and logic of the terms and conditions

which were incorporated into the arrangements. The evaluation sections contain an examination of how well each term and condition meets the four regulatory goals.

The sample itself is composed of 44 agreements, comprising 52 arrangements, selected from the surveyed agreements described in Appendix I. The arrangements were selected according to four criteria. These criteria in order of importance in the selection process are:

1. all general wheeling tariffs;

2. diversity with respect to the type of entities involved in the arrangements;

3. diversity with respect to the terms and conditions in the arrangements; and,

4. geographic representation.

Some of the agreements have two different types of wheeling services contained within one agreement; that is, both firm and nonfirm services are offered. The services have different price structures and terms and conditions and, therefore, they are treated as separate arrangements. A total of 52 arrangements are examined. The arrangement identifying number, the filer of the arrangement, and other entities involved in the arrangement are listed in Table II.1.

Information for the explanation of the utilities' rationale for the terms and conditions in the wheeling arrangements was obtained through telephone interviews with utility representatives. Attempts were made to reach representatives of the 33 firms designated as the wheeling utilities for the 52 arrangements in the sample. Twenty-eight interviews, covering 42 arrangements, were successfully completed.

The comments from the utility representatives can best be summarized in the words of one who stated that: "The terms and conditions . . . represent more of a negotiated contract and compromise among the parties involved than any particular rationale on the part of [the wheeling utility]." It is evident

Table II.1

Selected Sample of Wheeling Arrangements for Detailed Examination

Arrg. No.	Utility	Service
1	Arizona Public Service	firm
2	Arizona Public Service	nonfirm
3*	Consumers Power Co.	firm
4*	Consumers Power Co	nonfirm/economy
5*	Otter Tail Power Co.	firm
6*	Otter Tail Power Co.	nonfirm/emergency
7*	Cleveland Electric Ill.	firm
8*	Florida Power Corporation	firm
9*	Florida Power Corporation	nonfirm
10	Mississippi Power & Light	firm
11	Mississippi Power & Light	nonfirm
12*	Pacific Gas & Electric	nonfirm
13	Interstate Power Co.	firm
14	Interstate Power Co.	nonfirm
15	Florida Power & Light	firm
16	Florida Power & Light	nonfirm
17	Cincinatti Gas & Electric	firm

18	Cincinatti Gas & Electric	nonfirm
19*	Missouri Utilities	firm
20	Alabama Power	firm
21	Alabama Power	nonfirm
22	Southern California Ed. Co.	firm
23	Florida Power & Light	firm
24	Florida Power & Light	nonfirm emergency
25	Tennessee Valley Authority	nonfirm
26	Black Hills Power & Light	firm
27	Public Service Co. of Indiana	nonfirm
28	Western Area Power Admin.	firm
29	Central Maine Power	nonfirm
30	Vermont Electric Power Co.	nonfirm
31	Allegheny Power System	firm
32	Niagara Mohawk	firm
33	New England Power Pool	firm
34	New England Power Pool	nonfirm
35	Central Vermont	firm
36	Montaup Electric Co.	firm
37	Montaup Electric Co.	nonfirm
38	New York Power Pool	firm
39	New York Power Pool	nonfirm

40	PJM Power Pool	firm
41	PJM Power Pool (new agreement)	firm
42	PJM Power Pool (new agreement)	nonfirm
43	Bangor Hydoelectric Co.	nonfirm
44*	New England Power Co.	nonfirm
45*	Bonneville IR-1	firm
46*	Bonneville FPT-2	firm
47*	Bonneville ET-2	nonfirm/nonemergency
48	New York State Elec .& Gas	nonfirm/emergency
49	Connecticut Light & Power	nonfirm/nonemergency
50	PASNY	firm
51	Niagara Mohawk	firm
52	Niagara Mohawk	nonfirm/nonemergency

*Tariff arrangements

that the decisions regarding the arrangements were not made unilaterally. Industry practices, regulatory requirements, and the specific goals and needs of the parties involved all influenced the terms and conditions of the wheeling arrangements. The specified terms and conditions cover economic, legal, and technical requirements which are relevant and important to the parties involved.

The goals of the firms involved in the transactions may differ, or even conflict, with the regulatory goals. Goals of return on investment, minimization of risk, and long-range planning for service needs all influenced the decisions of the firms and the wheeling arrangements studied in this sample.

II.2 Type of Transmission Service

II.2.1 Description

Two basic types of transmission service are contained in the arrangements surveyed: firm and nonfirm. Firm transmission service refers to service which can be interrupted for only limited, specified conditions including:

1. emergency situations created by factors beyond the control of the utility--for example, weather related failures;

2. possible impairment of the operation of the selling utility's system when the utility is operating responsibly--for example, unanticipated power flows threatening stability of the system;

3. scheduled maintenance, repairs, replacements, installation of equipment, or investigation and inspection; and,

4. violation of an important term or condition of the arrangement by other parties to the arrangement.

Generally, once a commitment is made to provide firm wheeling service, the transmission capacity is available and guaranteed, and the wheeling utility is obligated to provide service upon request. In arrangements involving nonfirm service, on the other hand, the selling utility makes no commitment for capacity

and will provide services only if the capacity is available at the time of the request. Usually the wheeling utility can interrupt service for a number of possible reasons. In the sample, the two types of service are almost equally represented. There are 27 firm arrangements and 25 nonfirm arrangements.

Typically, not all of the conditions for firm service are spelled out in the agreements but rather are assumed. Exceptions are Arrangements 3 and 4 of Consumers Power Company in which these conditions are clearly stated. More representative is Arrangement 17 of Cincinnati Gas and Electric in which the only stated reason for interruption is "uncontrollable forces." Nonfirm service usually has no stated reason for interruption but sometimes, as in Arrangement 12 of Pacific Gas and Electric, the arrangement specifies that deliveries will "only be accepted if capacity is available."

A number of factors, however, blur the distinction between firm and nonfirm services. It is surprisingly common for arrangements to contain restrictions on interruption of nonfirm services and to specify other conditions besides those mentioned above for interruption of what is referred to as firm service. In addition, the use of short-term firm agreements and emergency agreements also adds to the overlapping of services. An example of a nonfirm agreement which contains restrictions on when the service can be interrupted is Arrangement 44 involving the New England Power Company (NEPCO). The arrangement is nonfirm yet the service can only be interrupted "subject to NEPCO needs in servicing their own retail and wholesale customers." Two firm arrangements which demonstrate liberal interruption rights are Arrangements 31 and 32 both of which involve wheeling of Three Mile Island replacement power. The arrangements are considered firm by the utilities yet interruption of service is allowed if the capacity is needed to service their own customers. Arrangements 31, 32, and 44 do not clearly fit in either the firm or nonfirm categories and are sometimes referred to as conditionally nonfirm although they might just as easily be called conditionally firm. The Tennessee Valley Authority (TVA) refers to such arrangements by the term "miscellaneous service." Eight of the arrangements studied fell into the conditional nonfirm type of arrangement.

Only two of the arrangements involve short-term firm service, but like the conditional nonfirm or firm arrangements they can fall in between the two categories of firm and nonfirm. If the time period for short-term firm service is relatively brief and is renewable, then it can be very similar to nonfirm service. For example, if the time period for service is less than one day, then the selling utility may consider many other offers and uses for its transmission service which is one of the major advantages of nonfirm service. In the short-term cases, scheduling is done on a 48-hour basis for Arrangement 10 and on a weekly basis for Arrangement 31 so the time period of service is relatively short. Each of these arrangements allows the utility to capture a substantial amount of the benefits of offering nonfirm service.

Four of the nonfirm arrangements provide for emergency transmission services. As an example, Florida Power and Light's Schedule TA (Arrangement 24) states that emergency transmission service will be provided on an "if and when available" basis to the city of Tallahassee. The arrangement specifies that the duration of emergency service shall not exceed 72 consecutive hours for any single emergency. If the need continues for more than 72 hours, the service will be provided, if capacity is available, under another wheeling arrangement. Arrangement 48 of New York State Electric and Gas provides nonfirm emergency service to transmit power to Central Gas and Electric Corporation. The hourly scheduling for service allows for flexibility on the part of the wheeling utility.

In general, the intent of arrangements for emergency services is to take care of requirements for emergencies of short duration. However, the wheeling utility will comply with the request for transmission services only if the capacity is available at the time the service is requested.

II.2.2 Rationale and Evaluation

The rationale given by the utilities for the type of service in the arrangements is that they follow the requests for service from the buyers of the service. That is, the buyer determines the type of service that they want and if the service is in the interest of the seller and the capacity to provide the service exists, the utility will provide the service.

The primary goal for regulation that applies to this aspect of the arrangements is that of efficient-use to provide maximum use of a wheeling utility's transmission system within established reliability rules. The question is one of balancing the requesting utility's needs against the wheeling utility's capacity to provide firm or nonfirm service. However, the type of service will enter into the discussion of how other aspects of the arrangements meet the goals of achieving the revenue requirement, efficiency, equity or fair cost apportionment, and practicality and feasibility. For example, in the discussion of rates, the rates will be broken down into rates for firm service and rates for nonfirm service.

A potential problem in the concentration of arrangements in long-term firm service is in the dynamics of demand for wheeling services. It is possible that alternative uses may be more valuable, but they are unable to occur due to existing long-term firm agreements. On the other hand, long-term wheeling arrangements may allow certain efficiency-promoting transactions, such as unit purchases or long-term firm sales, to take place that otherwise would not happen.

In some instances, the costs associated with contract negotiations and regulatory requirements for short-term service may be greater than any potential benefit or require more time than the lead time usually available for the transactions. Therefore, the benefits gained from regulation may be less than the costs. Economic efficiency will be reduced, because the wheeling utility's transmission system will not be used at its maximum potential. This problem can be circumvented, however, through tariff arrangements that provide an existing mechanism for services to a number of eligible entities to meet short-term needs.

The goal of practicality and feasibility in wheeling arrangements is important from the regulatory standpoint. Each wheeling arrangement has its associated costs in terms of contract negotiations, setting rates, etc. If wheeling utilities were required to offer an overly large number of different types of wheeling services, the goal of practicality and feasibility would not be met.

II.3 Compensation Methods and Rate Forms

There are two general types of rate forms for wheeling services. The most commonly used type is a postage stamp rate which involves a flat charge per kW or kWh. The second type of rate form also takes mileage into account. Since the specific applications of these two types of rate forms vary substantially according to the type of service, firm and nonfirm arrangements will be discussed separately.

II.3.1 Firm Transmission Service

II.3.1.1 Description

Firm wheeling rates are generally based on the total embedded costs (fully distributed costs) of the transmission facilities of the wheeling utility. These fully distributed costs usually consist of:

1. return on the transmission rate base,

2. depreciation of transmission facilities,

3. transmission operation and maintenance expenses,

4. allocated taxes, and

5. some share of administrative and general expenses.

The annual fully distributed costs (FDC) allocated to the transmission function are then divided by a measure of the system peak (the single annual peak, an average of 12 monthly peaks, or some other measure of system peak) to derive an annual charge per kW:

$/kW/yr = (FDC) / (kW peak)

This annual charge may be adjusted to be a monthly, weekly, or daily charge. The methodology can also allow for different rates for different delivery voltages by including only the

costs for transmission associated with a particular delivery voltage in FDC.

Almost two-thirds of the firm arrangements in the sample use a one-part specific rate based on this methodology. The remainder of the firm arrangements use various other components, primarily distance, in addition to the fixed charge per kW or kWh in calculating rates.

Five arrangements use a mileage-based rate, but they vary as to how the mileage is applied. In Arrangement 46, Bonneville uses a kW times mileage rate based on the time of year, with a lower rate applied to off-peak months. The distance is determined by the airline miles between the receipt point and delivery point for the power to be wheeled. New England Power Company (Arrangement 44) originally used a rate based on kW and kW-miles. The Power Authority of the State of New York (PASNY, Arrangement 51) bases its rate on kW times mileage. Arizona Public Service (Arrangement 1) has a fixed charge, a kW charge, and a kW times mileage charge. Alabama Power Company (Arrangement 20) takes distance into account through zone designations of delivery points. Transmission rates (mills/kWh) vary by zone.

Allegheny Power System (APS, Arrangement 31) has a two-part rate based on both kW and kWh. Finally, the New York Power Pool (NYPP, Arrangement 38) does not explicitly charge for firm wheeling services. Rather, 9.2 percent of the savings in power production of the pool is given to the owners of the bulk transmission facilities. The PJM Power Pool originally had no charges for firm wheeling services but has since initiated charges based on kWs (Arrangements 41 and 42).

II.3.1.2 Rationale

The compensation method and rate form used in a particular wheeling arrangement often represent the result of a negotiated agreement between two or more entities. The rationale and interests, as well as the relative bargaining power, of the buyer and seller of wheeling services can be expected to differ. Yet, a mutually beneficial compensation method and rate form are usually agreed upon, as evidenced by the number of

wheeling arrangements in existence. The process of negotiation, mutual agreement, and resulting benefit to the parties involved are particularly evident in the power pool arrangements for wheeling power. In NYPP's Arrangement 38, for example, the negotiated agreement is to compensate the major owners of the bulk transmission services through a percentage of the savings in power production.

If the parties to a wheeling arrangement do not reach a negotiated agreement on rates and other terms of a contract, cost justification becomes an important part of the resulting litigation. Cost justification of the rates for wheeling services is important in negotiated agreements, as well, because the rates must still be approved by the FERC.

The rate paid for firm wheeling service can be expected to be higher than that for nonfirm service provided by the same utility. A utility representative from Mississippi Power and Light explained that long-term firm service can be thought of as the sale of capacity. In short-term firm service, the wheeling utility can take advantage of seasonal fluctuations in demand and sell wheeling services during the system's own low-demand periods. The selling utility's rationale for the rate differentials between firm and nonfirm service is that the highest rate of compensation is necessary for long-term firm service, followed by short-term firm, and nonfirm wheeling services, respectively.

A shift from the use of mileage-based rates (for kWs transmitted times miles) to postage-stamp rates (for kWs transmitted) reflects a changing philosophy, according to a representative at Bonneville. At one time, the philosophy was that the cost of building transmission lines should be passed on to the buyers of wheeling services. The buying utility might even have the choice between building its own lines or paying for another utility to build the lines. The newer philosophy at Bonneville is that postage-stamp rates are more appropriate for a complicated power system with many interconnections. The building of transmission lines has become a smaller fraction of fully distributed costs and, therefore, distance has less importance in establishing rates for wheeling services. A similar change in philosophy appears to have occurred in the New

England area. In Arizona, however, the mileage component is still important in determining rates for wheeling services because of the large geographic area covered by Arizona Public Service and the maintenance costs associated with transmission lines.

The rationale for Alabama Power Company's zone designations in its arrangement to wheel power for the Southeastern Power Administration (Arrangement 21) goes back earlier than 1950 when the government built the power projects. At that time there were no transmission facilities to deliver the power. Rates were developed to take into account investment costs and distance (zone designations of delivery points). Through the years, new rates have been negotiated to reflect changing costs. The rate form continues to reflect the historical context, however.

II.3.1.3 Evaluation

Each rate structure meets the goals of regulation in different ways. All rates except NYPP's are based on fully distributed costs.

If a sufficient rate of return is granted under full cost recovery, the utility can recover its investment either from its own ratepayers or wheeling customers. Therefore, the revenue requirement is met. The only problem exists when there is a discrepancy among regulating bodies and certain items are disallowed by all. Since New England Power Pool's (NEPOOL's) rates are not related to the cost of providing the service, whether the provider of wheeling services obtains the revenue required to be fully compensated for the services is unknown without additional information.

The efficient use criteria for regulation must be examined for each rate type separately. Generally, to obtain efficient use, rates should be set at a level at least as high as the marginal cost of the service and at a level where the most valued use would be willing to pay for the service. This is described in Chapter 3. The most common type of rate is a one-part rate based on kWs. Usually such rates allocate transmission costs based on the percentage of kWs transmitted for the service to all kWs

transmitted in the system. Therefore, the rate is not based on the facilities actually used and does not correspond to the actual marginal cost. Since the actual marginal cost is not used, whether or not the efficiency objective is achieved is indeterminate.

The equity objective appears to be met in that any one group is not unduly favored. The practicality and feasibility of implementing the revenue scheme is obviously achieved in that it is easy to calculate through normal metering techniques.

II.3.2 Nonfirm Transmission Service

II.3.2.1 Description

The compensation methods and rate forms for nonfirm service are similar to those for firm service. The nonfirm can be categorized as conditional with limitations on interruptions of service or interruptible at will.

An example of the rate form of the former type is the NEPCO tariff (Arrangement 44). The numerator of the rate equation is based on fully distributed costs, as discussed for firm rates. However, the denominator is the system capability rather than system peak, as is the case for firm rates:

$/kW/yr = (FDC) / (kW system capability)

System capability includes kW capability of all generating units and may also include the kW capability of interconnecting points with other systems which could be used for importing power. It is a measure of the peak load that could be supplied during a given time by a system; therefore, it includes reserves. Since system capability is larger than system peak, the annual charge per kW developed by using system capability in the denominator of a rate equation will be less than if system peak were used in the denominator.

Almost all the rates for unconditionally interruptible nonfirm service are stated in terms of charge per kWh. An example of the methodology used is to divide the monthly firm rate (a per kWh charge) by 730 (the number of hours in a month):

kWh charge = (monthly kW charge) / (730)

The rate that results from this type of calculation is known as a 100-percent load factor rate. It represents the charge per kW, under the assumption that the same amount of power is wheeled 100 percent of the time. A 100-percent load factor rate is lower than a charge based on a lower load factor. For example, if a 50-percent load factor rate were being calculated in the immediately preceding equation, 365 instead of 730 would appear in the denominator.

A comparison of interruptible rates with firm rates shows that two utilities, Florida Power Corporation (Arrangement 9) and Mississippi Power and Light (Arrangement 11), appear to use a 100-percent load factor rate.

II.3.2.2 Rationale

The rationale for nonfirm transmission service, both to the buyer and the seller, was explained by one utility representative as being based on "potential economic benefit." Nonfirm service, by definition, is on an "if, as, and when" basis, although the specified conditions vary from one arrangement to another. The buyer would expect to pay a lower rate for nonfirm service because of less certainty of delivery and, under some circumstances, a degree of uncertainty may be acceptable. The seller, on the other hand, benefits from offering nonfirm wheeling services rather than having idle capacity. The seller would have to make little, if any, additional investment in order to offer nonfirm wheeling services.

Arizona Public Service's rates (Arrangement 2) include a fixed charge to cover the substation component plus a kWh and mileage charge. This schedule was formulated using the same rationale as for their firm service agreement.

Power pool arrangements again use the rationale of "mutual benefit" and "mutual agreement" among their members as the rationale for not allocating direct charges for nonfirm wheeling services.

II.3.2.3 Evaluation

As with firm wheeling service, whether or not the revenue requirement is met depends on the various regulatory bodies which govern the utilities. Most of the arrangements are based on fully distributed costs. Therefore, in these arrangements if the allowed rate of return is sufficient the utility would be able to meet its revenue requirement. In those arrangements where costs are not directly recovered, whether the revenue requirement is met is indeterminate. In the case of NEPOOL, the 9.2 percent of the pool savings may or may not pay for the transmission facilities. For NYPP the transmission service must be subsidized by other services. Whether the regulatory bodies allow this cross subsidization determines if the utilities meet their revenue requirements for the transmission facilities.

The goals of efficiency, equity, and practicality and feasibility with respect to compensation methods and rate forms for nonfirm service are similar to that given in the evaluation for firm service.

II.4 Billing Determinants

II.4.1 Description

Billing determinants are the factors (such as kWs or kWhs of use) to which rates are applied in order to determine the charges assigned to a specific wheeling customer. Most tariffs and rate schedules specify exactly how billing determinants are to be measured. A billing determinant is not always based on a customer's actual use. For example, the billing determinant could be contract demand kWs during the billing period. The contract demand kWs represent the capacity the wheeling utility has agreed to make available to the buying utility.

The most commonly used billing determinant in firm wheeling arrangements is kW contract demand. Cleveland Electric Illuminating (Arrangement 8) imposes a penalty if kW demand exceeds the contracted kW. Other arrangements specify the billing determinant as the higher of measured kW demand or the kW contracted. Florida Power Corporation (Arrangement 8) and Mississippi Power and Light (Arrangement 10) follow this method.

For nonfirm service, the most common billing determinant is actual kWhs delivered. An exception is Florida Light and Power (Arrangement 24) in which the billing determinant is the kW scheduled to be delivered.

For both firm and nonfirm service, Otter Tail Power Company (Arrangements 5 and 6) uses the maximum kWs of wheeling service, but it includes a 90-percent, 11-month demand ratchet. This means that the largest of either (1) the current month's kW use or (2) 90 percent of the highest kW use during the previous 11-months is used as the billing determinant for the current month. Bonneville (Arrangement 45) uses a coincident peak approach. Its billing determinant is the maximum kWs of wheeling service provided to a customer at the time of the Bonneville system peak.

II.4.2 Rationale

As discussed in the preceding sections, few of the arrangements are unambiguously of a firm or nonfirm type. The billing determinant would appear, at least in some instances, to be related to the degree of certainty that a specified level of power transmission services will be provided. For example, Connecticut Light and Power (Arrangement 49) provides nonfirm, short-term service to transmit entitlement power from Vermont Yankee nuclear plant to New Bedford Gas and Electric. The billing determinant is specified as kWs contracted, rather than delivered, under the assumption that the full 20,000 kWs of entitlement power would be delivered. Other billing determinants based on actual kWs delivered appear to assume less certain delivery of a specified amount.

The concept of the sale of capacity also explains the utility's rationale for charging for service based on the maximum of contracted or actual kW demanded. Whatever capacity has been contracted for in firm service should be paid for by the buying utility, even if actual deliveries fall short of this contracted amount. Any additional kW demand supplied should also be charged to the buying utility. Other utilities which base their billings on actual delivered kW or the kW demand at a certain

point in time explained this method as being reached through "mutual agreement" or negotiation. Although Cleveland Electric Illuminating Company (Arrangement 7) specified that there would be a penalty for exceeding contracted demand, a company representative reported that he did not know of a case where the penalty had been imposed.

II.4.3 Evaluation

Use of kW contract demand or the higher or contract or actual demand as the billing determinant helps assure that the revenue requirement will be met. The efficient use goal may not be met, however, if actual demand falls short of contract demand so that idle transmission capacity exists.

In nonfirm arrangements where capacity is not assured by the wheeling utility, the use of kWhs delivered as the billing determinant appears to meet the goal of equity, as well as practicality and efficiency. The buying utility is guaranteed no capacity and, therefore, pays only for the kWhs delivered. The goal of efficiency will also be met in that the use of the transmission system is increased within the limits of capacity to meet the needs of the buying utility.

II.5 Specific Requirements for Service

II.5.1 Entities Eligible for Service and the Direction of Wheeling Flow

II.5.1.1 Description

The discussion of entities eligible for service concerns who can obtain service under a particular arrangement. Of concern is whether limitations are placed on the direction of wheeling flows or limitations as to whom or from whom the power may flow.

Usually no restrictions on the direction of power flows are placed on the utilities, but at least one partner in the transaction is specified. Tariffs are generally open to a particular class of utilities (i.e., investor-owned utilities, municipals, or cooperatives) while rate schedules are more

specific in identifying eligible entities. Examples of tariffs are Arrangements 5 and 6 of the Otter Tail Power Company which limit service to municipals in Otter Tail's service area. The power pool arrangements' only internal limitations are that the arrangements are limited to pool members. Flows can go in any direction among members.

The rate schedules are more specific in their limitations. Perhaps the most stringent limitations are in Arrangement 1 of Arizona Public Service. This arrangement explicitly specifies the participants, the direction of power flows, and the points where interconnections will exist. A more common type is the arrangement between Florida Power and Light and the City of Tallahassee (Arrangements 23 and 24). In these arrangements, various utilities are allowed to transfer power over Florida Power and Light's transmission lines to Tallahassee. Reverse power flows are not allowed.

II.5.1.2 Rationale

The specified entities eligible for service can best be explained by the need or goal by which a particular wheeling arrangement came about. The needs range from the request for a simple delivery of power from point A to point B to the trading of power among utilities in an interconnected system. In the first type of arrangement the entities involved, interconnection points, and direction of power flows may be explicitly named, such as in Arizona Public Service's agreements (Arrangements 1 and 2) to deliver entitlement power from Cholla Generating Station to Utah Power and Light. Power pool agreements represent the opposite extreme where a number of entities, interconnection points, and directions of power flows are anticipated for the mutual benefit of the members of the pool.

Other arrangements may limit or explicitly specify the wheeling services because of the capacity limits of the transmission facilities of the wheeling utility. In the TVA system, for example, the transmission facilities were built to serve the TVA area, and no capacity was provided for wheeling. As a result, TVA currently has only two wheeling arrangements (one of which is included in this sample) which use marginal capacity of the system and limit the services to specified entities and points of receipt and delivery of power.

II.5.1.3 Evaluation

The limitations on the entities eligible for service and direction of power flows have implications for the goals of efficiency, equity, and practicality and feasibility. The revenue requirement goal does not directly apply to this aspect of service, assuming that the rates are based on fully distributed costs. In this aspect of service, the other three regulatory goals may be in conflict with one another. Limitations on eligible entities and the direction of flows may not enable the lowest cost power to be sold to its most efficient use. However, it may not be practical to allow power flows in either direction, because the effects of power flowing in reverse directions are not the same. Limitations on the participants when delivery is always through the same points on the wheeling utility's line would be overrestrictive. The effects on the wheeling utility would be the same in this case irregardless of the source of power.

The limitation of tariff arrangements to a particular class of utilities (i.e. investor-owned, municipals, or cooperatives) may affect the goals of efficiency and equity, inasmuch as it allows a utility to refuse wheeling service to another class of utilities or a nonutility, such as a cogenerator. In such a case, the efficient use of the wheeling utility's transmission system may be reduced, and different entities which desire service will not be treated the same.

II.5.2 Connection Requirements

II.5.2.1 Description

Connection requirements are limitations on the number of interconnection points through which the wheeled power can flow. There may be limitations on receiving points, delivery points, or both in the wheeling arrangements. Only four arrangements specify that any interconnection can be used for wheeling power. Typically, these are tariffs such as Arrangement 7 of Cleveland Electric Illuminating. The cooperatives and municipals that use this tariff can make use of

any interconnection as either receiving or delivery points. However, some rate schedules also specify that any interconnection can be used. An example is Arrangement 22 of Southern California Edison Company in which any substation bus can be used for wheeling.

The most common limitation on connections is where interconnection points are specified, but more than one set is allowed. Arrangement 26 of Black Hills Power and Light specifies various points where the power can be received from the Bureau of Reclamation [now the Western Area Power Administration (WAPA)] and points where it may be delivered to Rushmore Electric Power Cooperative. An interesting example of the number of interconnection points that can be specified is found in the NYPP agreements (Arrangements 30 and 39) in which 85 interconnection points are specified.

Arrangements specifying that only two connection points can be used (one at the receiving point and one at the delivery point) are also fairly common among the sampled arrangements. Such limitations are in 14 of the arrangements. Arrangements 13 and 14 limit wheeling to one interconnection with WAPA Power Authority and one with the City of Windom. Arrangements 1 and 2 of Arizona Public Service with Utah Power and Light also have this limitation.

Those arrangements which specify one interconnection at either the receiving or delivery end usually have the limit at the delivery end. Six of the arrangements limit the delivery points to one while only two place limitations at the receiving end. Usually the former type occurs when the utility buying the power buys from different sources. The two arrangements which specify only one connection at the receiving end are Arrangements 51 and 52 where PASNY uses Niagara Mohawk Power Company to wheel power to its preference customers.

II.5.2.2 Rationale

The designation or non-designation of receiving and delivery points depends upon the purpose for which the arrangement was set up, the technical nature of the systems involved, and the amount of flexibility desired by the parties to the agreement.

The tariff arrangement between Cleveland Electric Illuminating and rural electric cooperatives (Arrangement 7) allows for the maximum in flexibility and, thus, does not specify specific points. The rate schedule of Southern California Edison to provide transmission services to the City of Los Angeles (Arrangement 22) allows for delivery to any substation bus designated by the city, since this was the desire of the city. In the NYPP arrangements 85 interconnection points were specified; however, this number includes all those in the system and provides the maximum flexibility in transmitting power.

In the case of Interstate Power Company (Arrangements 13 and 14), the specified interconnection points are those required by this particular system to transmit power from WAPA to the City of Windom. The system of the city is interconnected with the company at two points, and the arrangement specifies one point as the normal point of delivery and the other as an alternate. Similar technical justifications were reported by other utilities that designated points of receipt and delivery of power.

A representative of the Black Hills Power and Light Company related the background information that explains the specified points of delivery to Rushmore Electric Power Cooperative (Arrangement 26). It became apparent in the 1970s that the western part of South Dakota would need additional transmission services. This transmission agreement resulted from joint studies by Black Hills, Rushmore, and Basin, the utilities which are electricity suppliers in the area. There are three phases of the agreement based upon the facilities to be constructed and the kinds of transmission services to be provided in the interim period. The specified points of delivery are part of the overall plan, and such specification was considered essential in setting up the agreement.

11.5.2.3 Evaluation

The primary goals of regulation applicable to this aspect of service are those of efficiency and practicality and feasibility. These goals may conflict with one another in this context. Transfer of power occurs efficiently if no limitations are placed on power flows. However, it may be more practical to

specify the interconnection points that will be used to avoid problems of ambiguity in providing wheeling services.

The goal of achieving the revenue requirement does not apply to this aspect of service except for cases in which costs of interconnections are part of the fully distributed costs included in rates. The goal of equity has possible application when rates are based, in part, on distance. In such cases, the most direct interconnection points would be considered the most equitable to the buying utilities.

II.5.3 Special Equipment Costs

II.5.3.1 Description

Special equipment costs are other fees associated with the wheeling arrangement besides those that are generally included in rates. Examples of such costs are charges associated with interconnecting the utilities involved in the wheeling transaction, such as expenditures for transformers, switches, capacitors, or meters. Less than 25 percent of the arrangements mention any special equipment costs. Few of these arrangements actually specify what equipment is necessary but rather specify who pays for any costs involved. One of the former arrangements is Arrangement 35 of Central Vermont which has a metering charge for each interconnection point.

Of the arrangements which specify who will pay for the costs, almost half place the responsibility for costs on the buyer of the wheeling service or the power. Typical examples are Arrangements 36 and 37 of the Montaup Electric Company. If any special equipment is needed Montaup will buy and install the equipment but the customer will then be required to reimburse Montaup. Some of the arrangements specify that the wheeling service will not take place if additional equipment is necessary. Arrangement 49 of Connecticut Light and Power Company specifies that no equipment will be bought.

Two of the arrangements have unique clauses with respect to special equipment costs. Arrangement 29 of Central Maine Power states that the responsibility for any required special equipment costs would be decided by binding arbitration. PASNY

In Arrangement 50 specifies that any special equipment installed by the buyer of the service on PASNY property will be the property of PASNY.

II.5.3.2 Rationale

The rationale for charging special equipment fees for the wheeling of power appears to be, generally, that the buyer should bear the cost, and these costs can be easily determined and justified. For example, Montaup Electric Company (Arrangements 36 and 37) requires that the customer reimburse Montaup, because "this seems the simplest way to handle special equipment costs." Central Vermont (Arrangement 35) imposes a metering charge to the buying utility for each interconnection point based on its standard practice for retail and wholesale customers.

In Arrangement 30 Vermont Electric Power Company (VELCO) specifies that each buying company will be assessed the full cost of any equipment installed to provide delivery of power. This requirement is based on the terms of VELCO's contract with the state of Vermont for wheeling power and the practicality of this method of reimbursing costs to the wheeling utility.

In the case of Connecticut Light and Power's arrangement to provide wheeling services to New Bedford Gas and Electric (Arrangement 49), the contract specifies that no equipment would be bought because of the short-term (two-months) nature of the service and the fact that no additional equipment would be needed. PASNY's specification that any special equipment installed by the buyer of the wheeling service would become the property of PASNY is based on what is considered normal practice in the industry. This specification is included in the arrangement to avoid any legal questions as to ownership and control of the equipment.

II.5.3.3 Evaluation

Special equipment costs, if they are required solely for the wheeling transaction, are a marginal cost of the transaction. If paid by the purchaser of the wheeling transaction, the revenue requirement, the efficient use, the fair cost

apportionment, and the practicality and feasibility objectives goals are satisfied. In the majority of the arrangements, it is specified that either special equipment costs will be borne by the buyer or that no special equipment will be purchased. Thus, the regulatory goals are met in this aspect of service.

II.5.4 Delivery Voltage

II.5.4.1 Description

A tariff or rate schedule may specify a range of voltage levels at which the wheeling utility is willing to make delivery. Some potential customers may be able to physically or economically take delivery only at one voltage level. Thus, as the range of delivery voltage levels increases, the number of potential users increases. For an individual utility, the cost of providing wheeling service increases as the delivery voltage decreases, mainly because one or more transformers are required to reduce the wheeled power to lower voltages. Also, there are some electricity losses associated with step-down transformation.

Delivery voltages in the sample varied from 2.9kV to 500kV. Only about 20 percent of the arrangements limited delivery to one specific voltage. Usually, delivery can be made at various voltages but often they are at fairly high voltage levels. The voltages at the higher levels usually only involve a specific line. Examples of arrangements with a higher voltage are Arrangements 1 and 2 of Arizona Public Service which involve a 345kV line.

Arrangement 35 of Central Vermont Public Service specifies various voltages: 7.2kV, 12.5kV, and 34kV. The PJM power pool (Arrangements 41 and 42) state that delivery can be made at any voltage. NEPOOL (Arrangements 33 and 34), however, limits delivery to 69kV and above. Arrangement 43 of Bangor Hydroelectric Company, in contrast, limits delivery to subtransmission voltage or lower.

II.5.4.2 Rationale

The specified delivery voltages are attributed to the technical requirements of the transmission lines, interconnections, and delivery points. Arizona Public Service (Arrangements 1 and 2) specifies higher voltages because the power system in the state consists of high voltage, interconnected lines. In Central Vermont's arrangement to wheel power to Vermont Electric Cooperative (Arrangement 35), the voltages are specified for points of delivery to meet VEC's requirements. From Central Vermont's standpoint, the specification of voltages is important because of the required investment to reach different voltage levels. The subtransmission voltage specified in Bangor Hydroelectric's arrangement (Arrangement 43) was requested by Eastern Maine Electric Cooperative, the buyer utility.

II.5.4.3 Evaluation

Similar to limitations on connections, limitations on voltages may decrease efficient use of the transmission system, since the flow of electricity is constrained. The delivery voltage level is an important factor influencing wheeling rates, however. To the extent that the cost of transforming equipment is incorporated into rates for wheeling services, the goals of revenue requirement, equity, and practicality and feasibility are met.

II.6 Notice and Response Requirements

II.6.1 Notice by Buyer for Initial Start of Service

II.6.1.1 Description

Usually, notification requirements for the initial start of service are not mentioned in the wheeling arrangements surveyed. If notice requirements are mentioned, in almost half of the arrangements all that is required is that there be a "reasonable" written or oral notice. In these cases, no specific time period for the notice is given. Arrangements 3 and 4 of Consumers Power Company fall into this category, requiring a "reasonable written notice" for request of service start.

Almost all of the centrally dispatched power pools require only that the buyer follow "normal dispatching procedures." Arrangement 43 of Bangor Hydroelectric Company, which is a member of NEPOOL, has this requirement.

Of those arrangements which have specific time limits for notification, the time required varies from one year to one week and they are all firm arrangements. The arrangement that requires one year is one of the exceptions among power pool members. Central Vermont's Arrangement 35 requires an annual notice on May 1. The shortest time period is in Arrangement 31 of APS which requires weekly notification for service start.

II.6.1.2 Rationale

In the majority of the arrangements surveyed, the buyer's desired date for the initial start of service was known and was mutually agreed upon during the negotiating process. Therefore, it is not considered necessary to add this item to the contractual arrangement. In the case of tariff arrangements, however, where a number of utilities are involved, this may not be the case.

In the arrangements covering centrally dispatched power pools, the request that the buyer follow normal "dispatching procedures" is mutually understood and agreed upon by the parties involved. In Central Vermont's long-term firm arrangement (Arrangement 35), annual notification for the start of service during the coming year was considered necessary so that Central Vermont can plan for capacity requirements. In APS's arrangement to wheel power to GPU (Arrangement 31), the weekly notification for service starts was required so that APS can plan for the needs of its own customers, as well as GPU, within the capacity limits of the system.

II.6.1.3 Evaluation

As with the other notification requirements, specific time notification for service start can provide a time period for the utility's analysis of the effects of a transaction on the wheeling system. However, this requirement can also be used to limit wheeling access if a beneficial purchase of power is only

known a short time in advance. But, the requirement also provides advantages to the buying utility in that the buyer knows specifically when it must request service. The vagueness associated with "reasonable notification" is avoided. Therefore, efficiency can be either reduced or increased, depending on the use that is made of this notification requirement.

The practicality and feasibility of the required notice by the buyer for the initial start of service is important to both the buyer and seller. "Reasonable" notification, although vague, may in some arrangements be more practical than an arbitrarily specified time. Although the goals of revenue requirement and equity are not directly applicable to this aspect of service, these goals are presumed to be met when the goal of practicality and feasibility is attained.

II.6.2 Response by Seller for Initial Start of Service

II.6.2.1 Description

The distribution of arrangements with respect to the response of the seller to a request for wheeling services is similar to those of the notice required for the start of service. However, there appears to be no strict relationship between the two. For example, only one arrangement, Arrangement 22 of the Southern California Edison Company, has a specific time period for both initial start and seller response. The response time varies from three days to 90 days. There is no relationship between length of response time and the type of arrangement. Both firm and nonfirm service are involved in the arrangements specifying three days and those specifying 90 days. Arrangement 7 of Cleveland Electric Illuminating requires a three-day response to a written request for firm service while Arrangement 12 of Pacific Gas and Electric requires a 90-day response to a request for nonfirm service.

Of those arrangements which do not specify particular time limits, a large number only require that central dispatching procedures be followed. Almost all of the arrangements involving members of centrally dispatched power pools fall into this category. Some arrangements use the words "promptly"

(Arrangements 10 and 11 of Mississippi Power and Light), "as soon as practical" (such as Arrangement 17 of Cincinnati Gas and Electric), or "immediately" (Arrangement 48 of New York State Electric and Gas). PASNY, as stated in Niagara Mohawk's Arrangement 50, must hold public hearings after Niagara Mohawk receives a request and before approving the request.

II.6.2.2 Rationale

The response time by the seller for initial start of service is included in the terms and conditions of the arrangements primarily at the request of the buyer. Although the initial start of service may have been mutually agreed upon by the parties involved, the buyer of wheeling services may request that the contractual agreement explicitly state the response time by the seller. In Southern California Edison's arrangement (Arrangement 22), the specified time requirements to request initial start of service and seller response were included by mutual agreement of the parties involved to avoid ambiguity or misunderstanding.

In Mississippi Power and Light Company's arrangements (Arrangements 10 and 11), the "prompt" response requirement was desired by the buying utility. The "prompt" requirement has proven satisfactory to the parties involved. In New York State Electric and Gas Company's arrangement (Arrangement 48), an "immediate" response was requested because of the emergency nature of the arrangement--to provide nonfirm emergency service to Central Hudson.

II.6.2.3 Evaluation

The response time, as in the case of notification for service start, allows the wheeling utility to determine the effects of the transaction on its own system. In the case of nonfirm service, the utility can determine if it has sufficient capacity for the transaction. If the response time is long, it can also be used to limit wheeling access if a beneficial purchase of power is only known a short time in advance. But, the response requirement also provides advantages to the buying utility in that the buyer knows specifically when the request must be answered. The vagueness associated with "as soon as practical"

is avoided. Therefore, as with notification for service start, efficiency can be either reduced or increased, depending on the use that is made of this notification.

The response time, to be practical and feasible, should meet the needs of the parties involved. Therefore, when the specified time is "mutually agreed upon," the goal of practicality and feasibility is presumed to be met. Also, the revenue requirement, efficiency, and equity goals are presumed met when the goal of practicality and feasibility is attained.

II.6.3 Scheduling Notice for Transactions

II.6.3.1 Description

Another notice requirement concerns the scheduling of wheeling transactions after the wheeling utility has agreed to provide service. Almost 80 percent of the wheeling arrangements mention scheduling notices. Centrally dispatched arrangements and those which mention specific time periods for scheduling notices account for almost all of those which mention scheduling notices. The length of time involved varies from hour by hour to 5 years. Arrangement 48 of New York State Electric and Gas requires hourly notice of scheduling while Arrangement 50 of Niagara Mohawk requires a 5-year forecast. The very short notices (hourly) and the very long notices (over 1 year) are for nonfirm and firm service, respectively. However, the intermediate time periods have no discernible pattern with respect to the type of arrangement. The 24-hour notices include a nonfirm arrangement (Arrangement 9 of the Florida Power Corporation) and a firm arrangement (Arrangement 3 of Consumer Power Company).

Those arrangements which do not specify a certain time period usually use the same language as is found in other notifications. Scheduling should be done "promptly" in Arrangements 17 and 18 of Cincinnati Gas and Electric and "orally or written" in Arrangement 7 of Cleveland Electric Illuminating.

II.6.3.2 Rationale

The amount of scheduling notice appears to be related to the nature of the wheeling services, as well as the incorporation of standard practices within a given utility or system at the time the arrangement was initiated. The hourly notice required by New York State Electric and Gas (Arrangement 48) is for nonfirm emergency service and, since true emergencies cannot be anticipated, hourly notice is a logical procedure for this service. On the other hand, in Niagara Mohawk's arrangement to provide firm service (Arrangement 50), the 5-year forecast is considered essential to the utility's planning for capacity needs.

Florida Power Corporation's arrangement for nonfirm service (Arrangement 9) stipulated that 24-hour notices were required, because it seemed "practical" at the time of the initial contract. At the present time, according to a utility spokesman, it is unlikely that this requirement is adhered to because of the economy energy brokerage system in the state to transmit energy in the most economical way. Scheduling is now on an hour-by-hour basis.

Consumers Power Company (Arrangement 3) requires 24-hour scheduling notices for transactions, because this amount of time is considered necessary to the efficient operation of wheeling services and, at the same time, to provide for the utility's own customers.

TVA (Arrangement 25) has changed from weekly to monthly scheduling of wheeling services, effective October 1, 1983. A representative of TVA reported that this change was being initiated to facilitate better planning within the TVA system.

II.6.3.3 Evaluation

Scheduling notice is an important part of a wheeling utility's ability to determine the effects of a given wheeling transaction on its system. The usage of lines can vary dramatically from hour to hour and scheduling sets forth the usage by the wheeling transaction. Adequate scheduling notice, from the standpoint of both the buyer and seller, is essential to the goals of efficiency and practicality. The buyer must be able to depend upon wheeling services within a defined scheduling routine. The

amount of time considered adequate varies from one utility system to another. The goals of efficiency and practicality, as well as the indirect goals of revenue requirements and equity, are presumed to be met when this aspect of service has been mutually agreed upon.

II.6.4 Notice for Interruption of Scheduled Service

II.6.4.1 Description

During the course of wheeling power, it sometimes is necessary to interrupt service for various reasons. Most firm service arrangements permit only very narrow and specific reasons for interruptions as discussed in Section II.2. Nonfirm service arrangements, on the other hand, have much more extensive and less strict reasons for interruptions. Often, interruptions can occur at the discretion of the wheeling utility. Due to these fundamental differences in allowable interruptions, it is important to examine the notice required before interruptions occur for both firm and nonfirm service.

Surprisingly, the distribution of notice requirements for interruptions is very similar between firm and nonfirm wheeling arrangements. As with other notice types, a specific time period is not usually specified in the arrangements. For both firm and nonfirm service, the most common requirement is that "reasonable" notice be given. Arrangement 15 of Florida Power and Light requires that reasonable advanced notice be given for interruptions of its firm wheeling service, while Arrangement 37 of Montaup Electric requires reasonable notice for their nonfirm service. However, for nonfirm emergency service no notice is required by Montaup Electric. Most of the remainder of the arrangements which mention notice requirements use similar language. The firm arrangements of APS (Arrangement 31) and PJM Power Pool (Arrangement 41) require "consultation with others in the arrangement" and "coordination with others," respectively. The nonfirm arrangements, Arrangements 9 (Florida Power Corporation), 11 (Mississippi Power and Light), and 25 (TVA), require "as much as possible," "when possible," and "prompt notification," respectively.

Only three arrangements give a specific time period for notice of interruption. Two of these arrangements, Arrangements 28 (WAPA) and 4 (Consumers Power Company), state that no notice had to be given. Interruptions may occur with no warning. Arrangement 28 is for firm service, while Arrangement 4 is for nonfirm service.

II.6.4.2 Rationale

As discussed above, no general conclusions may be reached concerning the notice for interruption of scheduled firm and nonfirm service, respectively. Each type of service is obviously subject to emergency interruptions for which no notice is possible. Other forms of allowed interruption and notice for interruption depend upon the mutual agreement and concessions of the parties involved. For example, the rationale for Montaup Electric Company's "reasonable notice" for the interruption of nonfirm service (Arrangement 37) is to give the buying utility the advantage of whatever information Montaup has so that the buying utility can make plans accordingly. Mississippi Power and Light (Arrangement 11) bases its procedure to give notification for interruption of service "when possible" upon a similar rationale. Although Florida Power Corporation (Arrangement 15) specifies that "as much as possible" notification be given for interruption of service, a utility spokesman reported that it is now unlikely that service would have to be interrupted except for a real emergency. This change is due to the shift to an energy brokerage system within the state.

The requirement for consultation with others for interruption of service is linked to the liberal interruption rights which are stated in Allegheny Power System's arrangement to wheel power to GPU (Arrangement 31). APS considered the liberal interruption rights necessary protection in order to meet the service requirements of its regular customers. As a concession to GPU, APS agreed to the requirement for consultation with the other parties when interrupting service. In PJM's Arrangement 40, participants must coordinate schedules for planned outages of transmission facilities so as to maintain reliable and efficient operation.

The TVA arrangement to wheel power to Big Rivers (Arrangement 25) requires "prompt notification" for interruption of service. In practice, TVA has had to interrupt the transmission service only two or three times, and these were unanticipated emergency conditions for which no notice was possible. In WAPA's arrangement (Arrangement 28) to provide firm service, no notice for interruption of service is required, because the service can be interrupted for emergency conditions only, under which no notice is possible.

The issue of interruption rights is of interest in Niagara Mohawk's arrangement to wheel power purchased by GPU from Ontario Hydro (Arrangement 30). The arrangement has been cancelled by GPU, because GPU found the liberal interruption rights of the firm service to be unacceptable, according to a representative of Niagara Mohawk. In the nearly 2-year period during which the arrangement was in effect, there were frequent interruptions of service. These interruptions were caused by Niagara Mohawk's own system requirements and capacity limits. GPU had depended on the wheeled power to replace the power previously supplied by the TMI nuclear plant and reliable deliveries were required. Consequently, GPU found another utility to provide wheeling services.

II.6.4.3 Evaluation

Interruption rights and the required notification for interruption of service are fundamental distinctions between firm and nonfirm wheeling services. The distinctions are not always clear-cut, however, as pointed out in other sections of this Appendix. The goals of revenue requirement, efficiency, equity, and practicality and feasibility are met to the extent that two conditions are satisfied: (1) the interruption rights and the required notification are stated clearly and concisely; and (2) rates reflect the degree of certainty or uncertainty for the provision of service and interruption of service.

II.6.5 Notice for Permanent Termination

II.6.5.1 Description

At some time either or both parties may decide to end the service under the transmission agreement. In order that a smooth transition may be made to other sources of power for the buying utility and other uses of the transmission lines by the selling utility, a time interval is sometimes specified for a notice of permanent termination of the wheeling service prior to the actual termination of service. Without such a notice or a clause stating that service could only be permanently terminated for specific reasons, service could theoretically be terminated at will if a better offer for the service appears.

Almost all of the 18 wheeling arrangements that mention permanent termination notices have a specific time period or date for termination. An exception is Arrangement 44 of the New England Power Company which states that the arrangement can be terminated at a time mutually agreed upon. Three arrangements have specific dates on which termination will occur. These arrangements are Arrangements 29, 30, and 49 of Central Maine Power, Vermont Electric Power, and Connecticut Light and Power, respectively.

The remainder of the arrangements specify a time period for the notice of termination ranging from 6 months to 4 years. There does not appear to be any relationship between the notice period and the type of wheeling service, that is, firm or nonfirm. The most common time period is 6 months. Examples are Arrangements 31 of APS and 48 of New York State Electric and Gas. The former arrangement is firm while the latter arrangement is nonfirm. The other wheeling arrangements, representing both firm and nonfirm arrangements, require notification of 1 year or longer. The New York and PJM power pools require 3-year notices for both firm and nonfirm wheeling arrangements.

II.6.5.2 Rationale

In Arrangement 44 of the New England Power Company which involves the wheeling of power to utilities in the New England area, the stipulation that the arrangement can be terminated at a time mutually agreed upon was considered to give adequate protection to all parties involved. This arrangement covers transmission requirements that are not covered by the NEPOOL agreement, and terms and conditions were developed by consensus of the parties involved.

The arrangement of Connecticut Light and Power (Arrangement 49) states a definite termination because of the specific short-term need to wheel entitlement power from Vermont Yankee to New Bedford Gas and Electric. In Vermont Electric Power Company's arrangement (Arrangement 30) to wheel power purchased by Vermont Marble Company and others from PASNY and Hydro-Quebec, a specific termination date was specified with the expectation that a new arrangement would be negotiated at that time. The parties involved felt that a specified duration of the contract offered them better protection against unforeseen circumstances than would an open-ended arrangement.

Each of the above described examples of arrangements requiring 6-months notice for termination was developed to meet the specific needs of the buying utility and required little, if any, capital investment on the part of the wheeling utility to provide the service. Therefore, a 6-months termination notice was considered adequate by the wheeling utility. The power pool agreements, on the other hand, serve a number of interdependent needs of member utilities, and the commitments are considered relatively long-term. Therefore, 3-years was agreed upon for termination notice.

II.6.5.3 Evaluation

Formal termination notices protect both the buyer and seller of wheeling services from sudden curtailment of service. Without such clauses it is possible that all four of the goals for regulation could be violated in some way. If specific facilities are built for the wheeling transaction and cancellation is not orderly, it is possible that the wheeling utility may not recover its investment. This would violate both the revenue requirement and the fair cost apportionment goals. Uncertainty as to when termination may occur could prevent or delay the capital investments necessary to provide firm service, in particular. Thus, the goals of efficiency and practicality would not be met.

The requirement of formal termination notice also protects the buyer of wheeling services and aids in the utility's planning to

provide electricity to its customers. Without such protection the goals of revenue requirement, efficiency, equity, and practicality and feasibility, from the buyer's standpoint, would not be met.

II.7 Miscellaneous Requirements

II.7.1 Type of Power

II.7.1.1 Description

Almost half of the arrangements place limitations as to the type of power which may be transferred under a wheeling arrangement. The type of power ranges from nonspecific (firm or nonfirm power) to a specific type of power (entitlement). A few of the arrangments mention particularly that any type of power can be wheeled.

All of the arrangements specifying that only firm or nonfirm power can be wheeled are firm or nonfirm wheeling arrangements, respectively. For example, Arrangement 47 of the Bonneville Power Authority states that only nonfirm power can be wheeled under this nonfirm wheeling arrangement. Alternatively, only firm power can be wheeled under the firm wheeling arrangement of Central Vermont Power (Arrangement 35).

Only about 15 percent of the total number of arrangements specify that only one particular type of power can be wheeled. Central Maine Power's Arrangement 29 allows only unit power from a particular generating unit to be wheeled under the arrangement. A number of arrangements, such as Arrangement 1, allow only entitlement power to be wheeled.

II.7.1.2 Rationale

Limitations as to type of power (firm or nonfirm, unit or entitlement) which may be transferred under a wheeling arrangement relate to whether a general or a specific need was addressed at the time the terms and conditions of the agreement were negotiated. The wheeling utility may wish to limit the arrangement to a specific type of power to avoid later problems. The wheeling utility can thereby attempt to protect

itself from claims that it has failed to provide the requested services when capacity limits are reached.

Also, rates may differ for the wheeling of various types of power. For example, Arrangement 47 of Bonneville Power Authority states that only nonfirm power can be wheeled under the nonfirm wheeling arrangement, because firm service is covered under a separate arrangement and rate schedule. Bonneville would not permit the wheeling of firm power under the lower-priced nonfirm arrangement. Central Vermont (Arrangement 37) specifies that only firm power can be wheeled because nonfirm service requires different handling and planning.

Arizona Public Service (Arrangement 1) provides for delivery of entitlement power only, because that is the desire of Utah Power and Light, the buying utility. Utah Power and Light wished to have terms and conditions that assure delivery of entitlement power, whereas the utility was willing to accept alternative terms and conditions for the transmission of other power needs.

II.7.1.3 Evaluation

Restrictions on the type of power that is wheeled may limit the type of power a buying utility can purchase, thus interfering with efficiency. Appropriate pricing policies can be used to solve the goals of meeting revenue requirements and fair cost apportionment. For example, if the utility selling firm wheeling services is concerned that if nonfirm power is transported not enough power will be transported to meet its revenue requirements, a take or pay pricing methodology may be used. From the standpoint of practicality and feasibility, the goal is met in arrangements which specify the type of power that is covered.

II.7.2 Special Terms and Conditions

II.7.2.1 Description

Only about one-third of the arrangements surveyed have special terms or conditions. These vary over the entire scope of terms and conditions discussed so far in this Appendix. A large number of the special terms and conditions, though, deal with

reimbursement of costs under special conditions. Three arrangements (Arrangement 5 of Otter Tail Power Company and Arrangements 8 and 9 of the Florida Power Corporation) specify that the utility buying wheeling services must pay for some part of the facilities used if the arrangement is cancelled. Arrangements 1 and 2 of Arizona Public Service require that APS be reimbursed for any regulatory fees charged due to the arrangement. If new taxes are added which affect the cost incurred as a result of providing wheeling services, Arrangements 17 and 18 of Cincinnati Gas and Electric require the buying utility to pay the added cost. Four arrangements adjust the rates charged with changes in the amount of power delivered. For example, if Florida Power and Light (Arrangement 15) is unable to deliver some or all of the power to the utility buying wheeling services, the rates are reduced.

The rest of the arrangements which have special terms or conditions are generally unrelated and specific to the utilities involved. Arrangements 13 and 14 of Interstate Power Company require the purchaser of the wheeling service, the City of Windom, to make their combustion turbines available for use by Interstate during peak periods. Missouri Utilities (Arrangement 19) requires a utility which buys wheeling services to install interruption devices. Arrangement 35 specifies that load limits can be placed by Central Vermont, the wheeling utility, at certain points along the lines. Finally, two arrangements (Arrangements 29 and 49 of Central Maine Power and the Connecticut Light and Power Company, respectively) state that binding arbitration will solve all disputes.

II.7.2.2 Rationale

The provisions covering reimbursement of costs to the wheeling utility are intended, generally, to minimize the utility's risk. For example, a spokesman of Florida Power Corporation explained that although no additional facilities were anticipated to provide service under its tariff arrangements, the stipulation was added that the buyer pay for some part of any additional facilities if the arrangement were cancelled. The spokesman does not know of a case where this requirement has been implemented, however.

The requirement by Interstate Power Company to the City of Windom, the buyer of wheeling services, to make combustion turbines available for use by Interstate during peak periods (Arrangement 13) was part of a negotiated contract which provides mutual benefit to the parties involved. Interstate Power Company pays the City for the power in the same manner as buying from the power pool.

Technical requirements account for the special conditions in some arrangements. Central Vermont in Arrangement 35 reserved the right to establish an electric load limit not to exceed 500 kW at any single phase point of delivery, reflecting the engineering limit that the system can handle before the power can be converted to three-phase.

Finally, the stipulation that binding arbitration will settle all disputes would appear to cover any unforeseen problems that are not already covered by a special term or condition. Connecticut Light and Power (Arrangement 49) added this stipulation, because "the parties involved would prefer arbitration to going to court."

II.7.2.3 Evaluation

The special terms and conditions which exist in the surveyed arrangements are all fairly minor points and thus would not tend to interfere with the goals of regulation.

II.7.3 Adjustment for Losses

II.7.3.1 Description

Almost half of the arrangements surveyed mention losses of power during transmission. The large majority of those which mention losses state the method used to calculate losses or state a particular percent of the power received by the wheeling utility that would be considered losses. NEPOOL (Arrangements 33 and 34) calculates losses from studies that are performed periodically. Connecticut Light and Power (Arrangement 49) estimates the losses involved in a wheeling transaction. Florida Power and Light uses historical average system losses in calculating losses.

The remainder of the arrangements which mention losses use fixed percentages for losses. The fixed percentages range from three percent in Arrangement 25 of the Tennessee Valley Authority to seven percent in Arrangement 28 of WAPA. One arrangement (Arrangement 22 of the Southern California Edison Company) calculates losses as .023 percent of kilowatt miles.

II.7.3.2 Rationale

The losses specified in these arrangements were based on periodic studies and estimates of system-wide average losses, subject to approval by the parties involved. One utility spokesman stated that the estimates of losses must appear "reasonable" to the parties involved. The method of calculation and the estimated value are both negotiated and settled by mutual agreement.

II.7.3.3 Evaluation

Without detailed load flow studies the losses stated in the wheeling arrangements are arbitrary. As explained in Chapter 2, losses may have no direct relationship with the most direct lines involved in the wheeling arrangement. Therefore, the goals of revenue requirement, efficient use, and fair cost apportionment may or may not be satisfied. However, the goal of practicality and feasibility is certainly satisfied when a single percentage is used for losses.

II.7.4 Reactive Power Factors

II.7.4.1 Description

Reactive power is power which is returned over the transmission lines from the utility buying power to the wheeling utility. Such power provides no useful work and is dangerous to the stability of the wheeling system. Therefore, most utilities assume that the utility buying power will maintain a reactive power factor as close to unity as possible. However, 40 percent of the arrangements specifically mention that the power factor must be maintained close to unity or a penalty fee will be charged for given deviations from unity.

Four arrangements specify that the wheeling utility is not obligated to continue service if the power factor falls below 85 percent. This stipulation is contained in Arrangements 45, 46, and 47 of the Bonneville Power Authority and Arrangement 50 of the Power Authority of the State of New York. Arrangement 19 of Missouri Utilities states that a power factor of 95 percent must be maintained. Cleveland Electric Illuminating in Arrangement 7, along with eight other arrangements, requires the utility buying power to maintain a factor near unity. Cincinnati Gas and Electric (Arrangements 17 and 18) and Alabama Power (Arrangements 20 and 21) require that no undue burden be placed on them due to reactive power but do not specify what constitutes an "undue burden."

Only four arrangements have charges for reactive power. Arrangements 5 and 6 of Otter Tail Power Company charge $0.15 per kVAr for reactive power over 0.33 kW. Florida Power Corporation in Arrangements 8 and 9 charges $0.063 per kvar for power factors less than 97 percent.

II.7.4.2 Rationale

Representatives of the surveyed utilities agreed that a power factor near unity should be maintained and that requirements concerning power factors were included in the arrangements as protection for the wheeling utility. The point at which reactive power becomes an "undue burden" and the rationale for specific points were not fully explained.

The representative from Alabama Power Company stated that the utility did not feel it necessary to specify what constitutes an "undue burden" in its wheeling arrangements. The utility would expect that a power factor near unity be maintained but would consider the trend more important than a drop in the power factor in a single day.

The charge for a power factor below 97 percent is specified for Florida Power Corporation's protection in its wheeling arrangements. However, according to a utility spokesman, it is unlikely that this charge has ever been imposed. As a practical matter, according to this representative, the power factor would be very difficult to measure in an interconnected system.

II.7.4.3 Evaluation

Reactive power can cause serious problems and costs for a wheeling utility. Except for very small transactions, reactive power may threaten the stability of a large part of the system. Therefore, the cost may be too high to have a charge. The four regulatory goals of revenue requirement, efficiency, equity, and practicality and feasibility can best be met in arrangements that specify an unambiguous power factor at which problems may occur and state the action that will be taken (penalty or interruption of service) when the power factor drops below the specified power factor.

Appendix III
Disputed Issues in Selected FERC Cases Involving Wheeling

In general, the descriptive material in other sections of this report has made no attempt to distinguish between wheeling terms and conditions about which there was agreement among the relevant parties and those which were disputed, litigated before the Commission, and decided by the Commission. The purpose of this Appendix is to focus only on those wheeling terms and conditions in selected cases involving wheeling issues that have been litigated before the Commission and where either the Commission has issued a final decision or there is an initial decision of an administrative law judge (ALJ) pending before the Commission.

The following disputed cases were selected for review:

1. Cleveland Electric Illuminating Company, Opinion 84, Docket No. ER75-194;

2. Otter Tail Power Company, Opinion 93, Docket Nos. E-8152 and ER77-5;

3. Kentucky Utilities Company, Opinions 116 and 116-A, Docket No. ER78-417;

4. Southeastern Power Administration vs. Kentucky Utilities Company, Docket No. EL80-7;

5. Florida Power and Light Company, Opinion 152, Docket Nos. ER77-175 and ER78-19 et al.;

6. Pacific Gas and Electric Company, Opinion 143, Docket No. ER76-532; and

7. Limits for Percentage Adders in Electric Rates for Transmission Services, Order 84, Docket No. RM79-29.

For each case, the important wheeling issues are identified. Then for each issue in each case, the positions of the various parties in the case are summarized, and the Commission's final decision or ALJ recommendation is discussed. Only the wheeling related issues in these cases are discussed. Some of the cases involved a number of other issues which either were totally unrelated to wheeling or were not unique to the issue of wheeling (e.g., rate of return). Moreover, wheeling issues that were settled prior to the Commission's decision were not discussed.

III.1 Cleveland Electric Illuminating Company, Docket No. ER78-194

The City of Cleveland, Ohio (city), petitioned to intervene when Cleveland Electric Illuminating Company (CEI) filed a Transmission Service Tariff which would allow rural electric cooperatives and municipal systems located within the Central Area Power Coordination Group (CAPCO) territories to wheel power purchased from other entities through CEI. Cleveland has a municipal electric utility which is a wholesale customer of CEI and a prospective recipient of the wheeling service. The tariff went into effect on February 28, 1978 subject to refund.

The tariff was filed by CEI as a consequence of certain conditions included in the operating licenses issued by the Nuclear Regulatory Commission (NRC) for nuclear power plants. The NRC Board determined that certain aspects of applications made by CAPCO members would be inconsistent with the antitrust laws. Specifically, CEI had refused to wheel to the municipality of Cleveland which was isolated from sources other than CEI and was able to obtain only emergency power from CEI. As a result, CEI was ordered by NRC to implement licensing conditions which concerned engaging in wheeling for other entities (electric generation and/or distribution systems, municipalities and cooperatives) in the CAPCO territories.

The FERC hearing was initiated to rule on the "justness and reasonableness" of the tariff provisions filed by CEI. In addition to CEI and the city of Cleveland, FERC staff presented evidence in the case. The initial decision was issued on April 27, 1979. The Commission's opinion (Opinion 84) was issued a

year later on May 5, 1980. The issues which focus specifically on the wheeling provisions are discussed below. Other issues (for example, billing and rate of return) were examined in the decision but are not discussed here.

III.1.1 Service Restriction

III.1.1.1 Disputed Issue

Should the tariff provisions be restricted to municipal systems and rural electric cooperatives (RECs) as proposed by CEI or should CEI list other entities (such as cogenerators and irrigation districts) as being eligible for service?

III.1.1.2 Positions of the Parties

The Commission staff and the city both argued that transmission service should be made available to a larger group of electricity producers and purchasers. They pointed out that CEI's suggested service restrictions violated the NRC license condition requirement. Staff argued that not including cogenerators, state or federal agencies, and water or irrigation districts within the tariff provisions violated the intent of the Public Utility Regulatory Policy Act (PURPA). The city suggested that the service restrictions would result in unlawful discrimination and thereby violated the Federal Power Act.

In defense, CEI pointed out that municipals and RECs were the only electricity generators/distributors in the service area and were thus the only ones who would need wheeling services. CEI indicated a willingness to negotiate a wheeling arrangement with other entities once they came forward. However, since it is possible that a different rate design would be required for these other entities, CEI did not want to include them in the tariff provisions under review.

III.1.1.3 Commission Decision

In the initial decision, the judge argued that FERC had no authority to order a utility to wheel power unless there was a specific refusal to wheel, which would constitute a violation of PURPA. CEI was within its rights to restrict the tariff

provisions to municipalities and RECs. However, if CEI were to refuse to wheel power for another entity, such as a cogenerator, that petitioner could request intervention from FERC. The Commission agreed, stating that "[i]n the absence of a concrete situation, we are not inclined now to require the tariff to provide for the extension of service to other types of entities."

III.1.2 Availability of Service

III.1.2.1 Disputed Issues

The tariff provisions authorized CEI to exercise a considerable degree of discretion in terms of how service would be made available. These provisions fell under three general headings:

1. Form of notice. CEI did not establish a requirement to notify potential customers why they were being denied service.

2. Sole discretion. CEI asserted that it would be the sole judge as to whether or not transmission services were available.

3. Curtailment. CEI did not specify how potential transmission capacity shortages would be allocated.

The question was whether or not CEI could reserve this degree of discretion over service availability.

III.1.2.2 Positions of the Parties

The city argued that the language of the tariff set the stage for potential unnecessary refusals to wheel by CEI. Since service could be terminated at the "sole discretion" of CEI, there was no standard on which to base an evaluation of the reasonableness of the curtailment. The staff pointed out that the provisions could be discriminatory in practice since CEI could cut service to its wheeling customers first in periods of capacity shortfalls in order to continue service to wholesale and retail customers. The staff suggested that a prorating of shortages across all customers might be a viable solution to the issue.

CEI responded to the criticisms of the provisions by pointing out that there was general agreement over the basic need for CEI to be the one to determine the availability of service. CEI expressed its willingness to change the tariff provisions to require a justification of a denial of service.

III.1.2.3 Commission Decision

The administrative law judge ruled that CEI should be required to give oral notification of the reasons why transmission service was to be denied, followed within three days with written confirmation. The judge agreed with the city that the use of the phrases "sole discretion," "sole judge," and "sole judgement" allowed for the possibility of arbitrary curtailment. He ruled that those phrases be deleted from the tariff.

The Commission affirmed the ALJ's decision but went a step further, requiring that the tariff specify the procedure CEI would follow if curtailment became necessary. As an interim curtailment provision, the Commission ruled that CEI should adopt the language of the NRC's license condition No. 3, which provided in part that "[i]n the event [CEI] must reduce wheeling services to other entities due to lack of capacity, such reduction shall not be effected until reductions of at least 5 percent have been made in transmission capacity allocations to other [members of the Central Area Power Coordinating Group] and thereafter shall be made in proportion to reductions imposed upon [the other members]."

III.1.3 Planning Future Transmission Capacity Needs of Wheeling Customers

III.1.3.1 Disputed Issue

Should CEI be required to include the anticipated future wheeling requirements of its wheeling customers in its plans for new transmission capacity?

III.1.3.2 Positions of the Parties

Staff and the city took the position that unless CEI were required to enlarge its transmission system in order to accommodate a potential growing number of wheeling customers, there would be noncompliance with the NRC license condition. In addition, the staff argued that wheeling customers would be faced with a high degree of uncertainty over whether or not wheeling services would be made available to them in the future.

CEI made a distinction between agreements dealing with current capacity and those involving future construction. CEI argued that since projected capacity changes do not affect the financing of current service, the proposed tariff need not require that capacity planning include forecasted increases in the demand for wheeling services.

III.1.3.3 Commission Decision

In a reversal of the initial decision, the Commission agreed with the staff's position that wheeling customers' load growth must be included in capacity planning in order to provide a "reasonable degree of certainty" that transmission services would be available. The Commission recognized that such a responsibility for CEI had to be met with commitments by wheeling customers to either use the transmission facilities or to compensate CEI for their construction. The Commission suggested that the parties involved could draw up an agreement regarding the future use of the planned transmission facilities, subject to the approval of the Commission.

III.1.4 Minimum Reservation Period

III.1.4.1 Disputed Issue

The controversy in this tariff provision involved the requirement that potential wheeling customers make a written request to CEI for transmission services for a period not less than 12 months.

III.1.4.2 Positions of the Parties

The city argued against both the written-request requirement and the provision for only long-term service. The city pointed out that wheeling customers might be able to obtain lower-cost, short-term power on relatively short notice but that the tariff provisions could prevent such transactions. It was, therefore, the city's position that the provision was unreasonable.

The staff based its objection to CEI's provision on the lack of evidence to support the restriction to long-term service. Since CEI already provided short-term power to the Ohio Power Company, there was a presumption that such service could be offered to others.

CEI defended its position by pointing out that short-term wheeling services could still be requested, only such service would be covered by a different tariff agreement. CEI anticipated that only long-term service would be demanded since the most likely supplier, the Power Authority of the State of New York, had a minimum 12-month commitment. It was argued that planning, scheduling, and rates would be drastically different for short-term as opposed to long-term service. Therefore, it was asserted that separate provisions would be required.

III.1.4.3 Commission Decision

The administrative law judge rejected CEI's arguments. Since CEI already provided short-term service, the limitations established in the provision were found to be unreasonable. The Commission affirmed the ALJ's ruling that the reservation period for transmission service be reduced to one week (or longer). There was no evidence presented to support CEI's contention that short-term service would require different terms for service or higher rates. As in the case of long-term service, CEI would retain the right to refuse short-term service when capacity was unavailable.

III.1.5 Transfer of Title to the Power Wheeled

III.1.5.1 Disputed Issue

The filed tariff included the provision that "[f]or the purpose of dispatching, CEI shall take and retain title to the power and energy delivered to it for transmission until it is delivered to customer."

III.1.5.2 Positions of the Parties

CEI argued that it required title for two reasons. First, energy received from another utility could not be distinguished from CEI's own generated power once it became commingled on the line. It is not possible to deliver a specific unit of power, only a specific quantity. Second, CEI argued that it required title in order to better control and dispatch the loads on its system.

The city countered with the argument that CEI did not need title in order to maintain control of its system loads and that there would be "minimal practical effect" on dispatching practices. However, the provision could cause hardship on the city in two ways. First, the loss of title to the power, even temporarily, could affect the city's trust indentures. Secondly, since the city, not CEI, was a priority purchaser of PASNY-generated power, the transfer of title could violate the preference arrangement. The staff agreed with the city that there did not appear to be any "economic purpose" to the transfer of title provision.

III.1.5.3 Commission Decision

The Commission affirmed the initial decision to delete this provision on transfer of title. By obtaining title, CEI would in effect become the supplier of the power rather than the wheeling agent. Since electricity is a fungible product, there is no need to be able to identify specific units of energy from the supplier and deliver it to the customer. Transmitting a quantity equal to the amount delivered (less line losses) is standard practice. The city did not substantiate its claims regarding preference power and trust indentures. However, since CEI could not support its tariff provision as being reasonable, the transfer of title provision was not upheld.

III.1.6 Method for Allocating System Control and Load Dispatching Costs

III.1.6.1 Disputed Issue

In its calculation of the cost of service, CEI estimated that the transmission function should include distribution load dispatching expenses ($613) and power supply system control and load dispatching expenses ($428,374).

III.1.6.2 Positions of the Parties

The city argued that these expenses should not be allocated to transmission, but instead were more appropriately allocated to the distribution and production functions. It was pointed out that CEI's proposed allocation was in variance with the provisions set out by the Uniform System of Accounts, 18 C.F.R. Part 101. CEI argued that load dispatching activities provided benefits to all those using the bulk transmission service.

III.1.6.3 Commission Decision

The administrative law judge found that CEI had been inconsistent in the treatment of its accounts. The Uniform System of Accounts gives utilities a choice; it is possible to: (1) carry load dispatching and system control expenses in a production account (Account 556) or (2) spread the expenses to the accounts dealing with distribution (581), transmission (561) and production (556). Since CEI had chosen to spread out the costs into the three accounts, it could not then decide to allocate all of these expenses to the transmission function for the purpose of the tariff. The Commission concurred with the ALJ's ruling.

III.1.7 Proper Assignment of Distribution Station Capacitors and High-Side Breakers

III.1.7.1 Disputed Issue

Should distribution high-side breakers and capacitors be treated as a transmission related expense?

III.1.7.2 Positions of the Parties

The city again pointed out an accounting-related discrepancy. CEI's accounting practices indicated that these investments were classified as distribution related. CEI argued that the capacitors and breakers under discussion were required to maintain the proper voltage in the transmission system.

III.1.7.3 Commission Decision

The Commission affirmed the administrative law judge's decision that CEI had not satisfied its burden of proof in this issue. CEI needed to show that the distribution system capacitors and breakers would have been installed for transmission even if there had been no distribution function. Since CEI's witness could not confirm this assertion, the investment was to be allocated to distribution.

III.2 Otter Tail Power Company, Docket Nos. ER77-5 and E-8152

This proceeding was the first in which the Commission had to deal exclusively with establishing a rate for wheeling power. The Commission investigation developed because of a Supreme Court Decision in an antitrust case (Otter Tail Power Company vs. United States 411 U.S. 336 (1973 aff'g 331 F.Supp. 54 (D. Minn. 1971))) in which Otter Tail Power Company's (Otter Tail's) previous refusals to wheel power were judged to be in violation of the Sherman Act.

In order to understand some of the complexities of the case, a short history of the significant events leading up to this proceeding is needed. Between 1950 and 1977, Otter Tail wheeled wholesale power to certain municipal systems under a contract with the United States Bureau of Reclamation (USBR). Under this contract, USBR sold power to municipal systems and arranged for wheeling with Otter Tail at a rate of one mill per kWh. Special services (firming) agreements were included in the individual customer's contracts.

In 1955, the USBR contract was modified to provide that Otter Tail would not be required to wheel to municipals that had once

been retail customers of the company. The village of Elbow Lake, a former purchaser of Otter Tail power, came up against this modification when, in 1962, it formed its own municipal utility. Although USBR was willing to supply the village with power, Otter Tail refused to wheel the electricity.

The Justice Department brought suit against Otter Tail for attempting to monopolize the electric power market in its service area (331 F.Supp 54 (1971)). Otter Tail was enjoined from refusing to sell wholesale power to municipals and from refusing to wheel power generated by third parties. The Supreme Court specifically deleted that part of the Otter Tail/USBR contract which enabled Otter Tail to refuse to wheel power to former retail customers (410 U.S. 366 (1973)). At this point, Elbow Lake again requested Otter Tail to provide wheeling services. However, the company never provided Elbow Lake with service under the USBR contract.

In 1973, when Otter Tail filed rates with the Commission to initiate wheeling service, Elbow Lake intervened. The village asserted that the transmission rate was unduly discriminatory because the rate was in excess of those charged under the USBR contract. The Commission, however, accepted Otter Tail's rate as an initial rate not subject to refund. When the final USBR contract expired, Otter Tail filed to increase rates for transmission service to those cities covered by the contract. The Commission designated this proposed rate schedule as a change in rates subject to refund. So, in 1977, the new rates went into effect, subject to refund, to all municipals except Elbow Lake. The cities involved requested that the Commission compel Otter Tail to make the terms uniform and to make the refund provisions applicable to Elbow Lake.

The initial decision dealing with the proceeding was issued on September 15, 1978, covering Docket Nos. ER77-5 and E-8152. The Commission's opinion (Opinion 93) was issued almost two years later on August 15, 1980. The parties making arguments in this case included: Otter Tail; the Commission staff; representatives from the affected towns, including Alexandria, Ortonville, Tyler and Warren in Minnesota, and Big Stone City in South Dakota (cities); and those representing the U.S. Department of Energy, including the Office of the Secretary of Energy and the Western

Area Power Administration (WAPA has taken over the responsibilities of USBR).

The major purpose of the case was to establish an appropriate tariff for Otter Tail's wheeling customers. The following topics highlight some of the issues brought up by the case that deal specifically with wheeling. Those topics addressed by the case but not summarized below include rate of return, income tax treatment and tax normalization, supplemental and emergency service, the question of satisfaction of FERC filing requirements, and whether or not Elbow Lake had been discriminated against in the rate design.

III.2.1 Rate Base

III.2.1.1 Disputed Issues

There was considerable controversy over what facilities should be included in the rate base for Otter Tail's wheeling customers. Several subissues were identified as part of this dispute:

1. Transmission lines, step-up transformers and associated equipment. Should certain of these facilities be included in the rate base?

2. Production. Should the incremental cost of building a plant at Jamestown rather than Big Stone be included as a transmission expense?

3. Distribution. Should the rate base include some of the oil circuit breakers, line sectionalizing switches and capacitor banks?

4. Materials and supplies. What percentage of the cost of materials and supplies should be allocated to transmission?

5. Beginning and end of year average versus 13 monthly balances average. Which method presents the most representative value for the estimated rate base?

III.2.1.2 Positions of the Parties

There was a long list of objections to the inclusion of some of the transmission facilities in the rate base, each objection carefully based on a different set of arguments. The staff felt that some of the transmission lines had been built to reduce production costs by increasing reliability. Thus, these facilities were more appropriately allocated to the power supply function. The staff and WAPA felt that some of the other transmission lines should be withdrawn because they duplicated functions being provided by lines built by WAPA, not Otter Tail. The cities argued that transmission lines which extended far beyond the high-density portion of Otter Tail's service area should be excluded. The cities felt that these lines were for the most part used to transmit emergency power and thus served a power supply function. WAPA objected to the inclusion of transmission lines which were used exclusively for the exchange of power between Otter Tail and other utilities.

Otter Tail provided counter arguments for each of the other parties' positions. The company provided evidence that each of its transmission lines was necessary to insure that proper voltage levels would be maintained throughout the system. In addition, Otter Tail pointed out that if the Commission endorsed the allocation of production-function attributes of transmission facilities to production, then a consistent posture would require the allocation of a transmission-function share of the cost of production facilities to transmission.

In the discussion of the production subissue, Otter Tail argued that the location of a generating facility at Jamestown saved the company from building a set of transmission lines from Jamestown to Big Stone (the alternate production site). Such a line would have cost $4.4 million, but the incremental costs of the Jamestown plant that Otter Tail felt should be assigned to the wheeling customers was $1.4 million. The cities argued that since the benefits ($3 million) do not accrue to the wheeling customers, neither should the costs. The staff, WAPA, and the cities argued that management made siting decisions on a number of factors, not all of which are quantifiable. Thus, the allocation of a portion of these costs to the wheeling customers would be arbitrary.

In the examination of whether or not to add the cost of the breakers, switches, and capacitor banks into the rate base for wheeling customers, all of the parties recognized that the equipment was physically located at distribution substations. The question was whether or not this equipment served a transmission function. The cities argued that the equipment should be allocated to distribution because the company had not shown that the equipment would be necessary if there were no distribution substations at those points. Otter Tail presented evidence to support its contention that the equipment allowed the company to disconnect the distribution and transmission lines when there was a line fault. Therefore, the switches, breakers, and capacitors were necessary to maintain the transmission system's reliability.

The question surrounding the allocation of materials and supplies was mainly one of degree. Otter Tail had allocated all of its materials and supplies account to the transmission and distribution functions. The staff had presented evidence that 3.7 percent should be allocated to the general plant account and that an additional one percent should be allocated to the production function.

The final controversy over the rate base issue involved the definition of the base year. Otter Tail had used a methodology in which it calculated the average of the rate base in the beginning and ending months of the test year. Otter Tail argued that this approach did not cause a serious distortion and represented accepted practice. The cities countered with the observation that although the use of a 13-monthly-balance methodology and the beginning-and-ending year methodology might give similar values based on actual test year data, such was not true for the estimated values on which the rate base was actually calculated. The cities argued that, since the company's major plant additions occurred in the last two months of the test year, a 13-month average was more representative.

III.2.1.3 Commission Decision

The Commission agreed with Otter Tail in the interpretations of the appropriate transmission and distribution equipment to be included in the rate base. The Commission ruled that ". . .

Otter Tail will provide its wheeling customers the amount of power contracted for from its most proximate source. As such, any facility which serves a transmission function is properly includable in the rate base." The Commission ruled that the rate base should not be limited to transmission facilities actually being used to serve current wheeling customers, but should encompass the whole transmission system because all the lines were "potentially useful in providing wheeling service."

The Commission also supported Otter Tail's argument for the inclusion of the breakers, switches, and capacitor banks at the distribution substations as part of the rate base. Reversing the recommendation of the administrative law judge, the Commission ruled that this equipment did perform a transmission function and should be included in the rate base for transmission services.

The Commission ruled that the incremental costs of locating the company's generating facility at Jamestown could not properly be included as a transmission expense. The cities' argument that siting decisions involved a number of different, unquantifiable factors, none of which could be unambiguously allocated to the wheeling customers, was affirmed.

The Commission accepted the staff's determination that only 95.3 percent of the materials and supplies account should be allocated to distribution and transmission. The Commission also accepted the cities' contention that the rate base should be calculated using a 13-month average balance approach.

III.2.2 Cost of Service

III.2.2.1 Disputed Issues

There were a number of issues concerning which costs were appropriately included in the estimated cost of service. The disputed expense categories included:

1. Should the cooperatives and Big Stone partner's load be included in the calculation of the transmission system load for the purpose of estimating the cities' proportion of costs? The cities' cost share had been calculated as

the ratio of the cities' peak load during the month of system peak to the estimated total system peak load. The question became how to define the total system load to make this calculation.

2. Should some electric revenues be deducted from the cost of service?

3. Is the methodology used by Otter Tail to estimate the cost of service for the test year reasonable?

III.2.2.2 Positions of the Parties

Otter Tail argued that since the loads from the cooperatives and Big Stone partners were served from jointly-owned facilities, those loads should not be treated in the same way as the loads from the company's other municipal and retail customers. By including the loads of the joint owners in the total system load, the revenues for wheeling services would be an estimated 50 percent lower. (The denominator in the ratio used to calculate the cities' proportion of cost would be twice as large as it would be if the cooperatives' and Big Stone partners' load were not included in the estimate of the total system load.) By treating the load of group investors in the same way as independent customers' loads, the Commission would discourage the construction of joint projects, which provide economies of scale. Otter Tail pointed out that the cooperatives, the Big Stone partners, and the company had all made investments in facilities roughly comparable to their share of the load. In most cases, the use of the facilities and the level of each enterprise's investment had been roughly equal; when equality was not achieved, then one of the parties to the joint project made a cash payment to Otter Tail for the use of the facilities. Therefore, to be consistent, Otter Tail argued that the cooperatives' and Big Stone partners' load should not be included in the total system load definition used in the calculation of the cities' share of transmission costs. However, the utility argued that equalization revenues received from them should be treated as a revenue deduction from the cost of service. The company agreed that other electric revenues, such as those received from power pool sales and wheeling for Manitoba Hydro, should also be deducted.

The Commission staff felt that the most reasonable approach was to include the loads of the cooperatives and Big Stone partners in the calculation of transmission system load but to incorporate an appropriate compensating charge to reflect Otter Tail's transmission expenses for their use of the integrated system. The cities supported the staff's analysis.

Otter Tail had developed some creative approaches to calculating the cost of service. The company computed its estimate for the cities' load using a 5-year period (1971-1972 to 1975-76) while the retail load projections were based on a 9-year period (1967-68 to 1975-76). The cities felt that the time periods on which the estimates were based should be consistent.

The other set of calculations involved estimates for the growth of transmission and operating expenses. Using Otter Tail's approach, Period II (1976-77) forecasts were almost 19 percent higher than the forecasts for Period I (1975-76). The cities, using historical data from 1972 to 1976, found that transmission operating and maintenance expenses grew at an annual rate of only 2.7-2.8 percent. The cities argued that Otter Tail had not satisfied its burden of proof that its estimation of the growth in the costs of operating and maintaining the transmission facilities was reasonable.

III.2.2.3 Commission Decision

The Commission agreed with Otter Tail's argument that the cooperatives' and Big Stone partners' load should not be included in the system load estimate and that electric revenues should be deducted from the cost of service. The Commission decided that this approach was reasonable and the only one that was presented which could be implemented. This allocation was consistent with the Commission's ruling that the line segments built by the company's partners should not be included in the rate base or considered in the calculation of the cost of service.

The Commission felt that Otter Tail had not shown that its methodology for estimating a 19 percent increase in transmission expenses was reasonable. Since the company's figures were so much higher than the cities' historical estimate of 2.7-2.8

percent, the Commission felt that there was serious doubt as to Otter Tail's approach. The Commission ruled that it would accept the cities' estimate.

III.2.3 Wheeling Rate Design

III.2.3.1 Disputed Issue

Given that the revenue requirements for Otter Tail's wheeling services have been determined, there was still a question of rate design. Otter Tail based its rates on the customer's greatest 15-minute kW usage. For the first six months of the year, peak was reflected by the previous winter's peak; for the last six months, peak was measured at the highest 15-minute demand for the current winter season.

III.2.3.2 Positions of the Parties

Otter Tail argued that the use of annual peak loads was necessary to insure the full recovery of costs on a system capable of meeting peak demands. Since the utility was faced with compliance with the antitrust decree, it argued that a rate based on annual peak to provide the requested firm service was required.

The cities and staff argued that Otter Tail had made an error in its calculation of rates. Rates are determined by estimating the ratio of revenue requirements to billing units. Otter Tail's tariff indicated that billing units would be calculated on the basis of the cities' 15-minute, non-coincident peak demands. However, the rate actually being used by Otter Tail reflected coincident peak demands at 60-minute intervals. The staff showed that the rate design in use could result in collections in excess of the specified revenue requirements. Otter Tail claimed that the rate had been approved in an earlier case (Village of Elbow Lake v. Otter Tail Power Co. 46 FPC 675 (1971), modified sub nom., Otter Tail v. F.P.C. 473 F.2d 1253 (8th Cir. 1973)) and that the possible overcollections were extremely small.

The cities presented an alternative rate design. They argued that the rate should be calculated using the higher of the

following two figures: actual peak demand for the month or 90 percent of peak demand over the previous 11 months. They argued that this rate structure would avoid the inconsistencies that could arise when costs are allocated on the basis of annual peak demand but payments are based on monthly peak demands.

III.2.3.3 Commission Decision

The Commission found that the wheeling rate design proposed by Otter Tail was inappropriate. The Commission agreed with the cities and staff that the problem with the procedure was that "it does not develop the annual rate in the same way that its customers are billed under the rate." The Commission approved the adoption of the cities' suggested use of the 90 percent rolling-rachet approach. This design was judged to be consistent and it had been used in other rate designs. The Commission felt that the new rate design would insure that the cost of service would be recovered without the danger of overcollections, as in Otter Tail's previous rate design.

III.2.4 Billing Determination

III.2.4.1 Disputed Issue

In addition to the question of rate design, the case also included an evaluation of appropriate billing procedures. Otter Tail's rate design required the use of the highest 15-minute demand for the current winter season in the last six months of the year. Therefore, in July, an estimate of the upcoming winter peak had to be used to send out a bill. The estimate was based on a 7 percent load growth factor being applied to last year's winter peak. When the actual peak demand was known, Otter Tail calculated the difference between the estimated and actual figures. Otter Tail would then make a retroactive adjustment on the cities' bill.

III.2.4.2 Positions of the Parties

Otter Tail argued that the 7 percent load growth factor was reasonable. Past growth had been in line with this estimate. The cities felt that the whole procedure was unnecessarily complicated and could result in overcollections.

III.2.4.3 Commission's Decision

The Commission did not object to Otter Tail's use of the 7 percent load factor. Since this figure was adjusted when actual winter peak was known, its use as an estimate was appropriate. However, as shown above, the Commission held against the rate design for which the billing procedure was used, and therefore the billing procedure would not be continued.

III.3 Kentucky Utilities Company, Docket No. ER78-417

This proceeding was initiated by the City of Paris, Kentucky to protest a rate increase filed with the Commission by Kentucky Utilities Company (Kentucky). Although the rate applied to Paris' wholesale purchases of power (not wheeling as defined in Chapter 2), the case highlighted how the Commission views the appropriate allocation of transmission costs based on the type of service provided.

After the filing of the rate increase, the new rates went into effect on September 6, 1978, subject to refund. The initial decision for Docket No. ER78-417 was issued on March 18, 1980. Those making appearances before the Commission on this case included representatives of Kentucky, Paris, the Electric and Water Plant Board of Frankfort, Kentucky, Kentucky Municipals, Jackson Purchase Electric Cooperative Corporation, Big River Electric Cooperative Corporation, and the Commission's staff. The Commission's opinion (Opinion 116) was issued on April 2, 1981. The Commission issued a second opinion (Opinion 116A) on June 1, 1981, in response to Kentucky's request for a rehearing. That request was denied.

Although the Commission examined the fuel cost adjustment clause and the appropriate value of the allowed rate of return, the major issue with implications for wheeling dealt with whether or not Paris should be required to bear some of the capacity costs of Kentucky's transmission system. This is the topic discussed below.

III.3.1 Transmission Capacity Costs

III.3.1.1 Disputed Issue

The rates that Kentucky developed included a transmission capacity cost allocation to Paris. Is the charge reasonable when Kentucky supplies Paris only with interruptible "secondary energy" which is surplus for Kentucky and its other customers?

III.3.1.2 Positions of the Parties

Paris pointed out that Kentucky was providing the city with interruptible power. The Kentucky/Paris agreement specified that Kentucky could interrupt and even curtail the delivery of secondary power for a maximum of 400 hours during any 12 consecutive months, but not to exceed 1000 hours over a five-year period. Paris had its own generating facilities with a capacity great enough to be able to serve its own peak load. Therefore, Kentucky was not obligated to provide power to Paris during the system's peak periods.

Kentucky argued that just like the other wholesale purchasers, Paris should be required to pay for some portion of the transmission system. The company had estimated the share of Paris' contribution to the average of the system's peaks each month for a 12-month period. This share was then used to allocate a portion of the transmission capacity costs. Kentucky argued that Paris should not be charged for generation capacity because of the interruptible nature of the supply arrangement, but that transmission was fundamentally different. Since transmission facilities have to be built to serve "demand throughout the year rather than peak demand," Kentucky felt that Paris should be charged for some of the needed capacity.

In the request for rehearing, Kentucky pointed out another special feature of transmission lines. Unlike generating units, which can be added together to calculate capacity, transmission lines connect specific points and help provide system reliability, stability, and flexibility. Thus, each load center must be incorporated into system planning.

Kentucky and the staff argued that it had been the Commission's practice in earlier cases to use a demand-related charge for transmission. In the request for rehearing, Kentucky presented interpretations of past opinions which showed that the rate charged to Paris was consistent with those in force in other service areas.

III.3.1.3 Commission Decision

The Commission ruled that Paris should not be charged a transmission capacity fee because of the interruptible nature of its supply. There was no evidence that Kentucky had built additional transmission lines to be able to serve Paris. The Commission agreed that the non-additive nature of transmission capacity made the transmission system planning different from generation. However, the Commission reminded Kentucky that the Commission's policy had been to treat transmission as an integrated system, with each portion being dependent upon the others.

The Commission indicated that it would be willing to consider the approval of a rate system based on marginal energy costs, given that transmission capacity costs were excluded, or some "different, non-traditional method of allocating transmission costs" which more adequately reflected Paris' use of the system. However, since such options were not developed in the record, they could not be addressed in this case.

The Commission rejected Kentucky's arguments that this decision conflicted with earlier decisions. It was pointed out that the previous proceedings dealt with firm power arrangements rather than the interruptible, nonfirm arrangement being examined in this case.

III.4 Southeastern Power Administration vs. Kentucky Utilities Company, Docket No. EL80-7

On December 11, 1979, the Southeastern Power Administration (SEPA) filed a petition with the Federal Energy Regulatory Commission (FERC) for an order to compel Kentucky Utilities

Company (KU) to provide wheeling services under the authority granted to FERC in sections 211 and 212 of the Federal Power Act as amended by the Public Utilities Regulatory Policies Act (PURPA) of 1978. The initial decision was issued on September 10, 1981, for Docket No. EL80-7. The Commission opinion was issued on November 8, 1983.

The proposed transaction in this case would involve the transfer of 25 MW of power generated by SEPA to KU, which in turn would deliver the power to eight municipals (cities) located in the KU operating area. Seven of the eight municipals are full requirements customers of KU. The other municipal (city of Paris) is a partial requirements customer of KU. Each of these parties presented arguments during the initial hearing in addition to those presented by the Commission staff.

The 25 MW of capacity involved in the transaction would have associated energy of only 1500 MWh per MW of capacity per year (17.1 percent availability). A further restriction on the energy involved is that the energy flow may not exceed 70 hours per week per MW of capacity.

SEPA proposed that KU schedule the power into the KU system at such times as it chooses (subject to the foregoing availability constraints) and treat the power as a system resource. KU, in turn, was asked to credit its monthly bills to the cities by the amount of capacity and energy that could be received each month by KU. This would be accomplished by deducting each city's allocated share of capacity from that city's monthly measured actual demand and by reducing the actual monthly energy consumption of each city by approximately one-twelfth of that city's annual share of the energy allotment. The city of Paris would receive no demand credit, since at the time of the hearing it was a partial requirements customer paying no demand charge to KU. SEPA would pay KU for transmission services provided.

III.4.1 Distinction Between Wheeling and Other Transmission Transactions

III.4.1.1 Disputed Issues

A major question during the litigation of this case was whether or not the proposed transmission transaction can be defined as wheeling. If so, the Commission could require KU to provide this service to SEPA. However, the statute giving such authority to the Commission does not define the terms "transmission services" and "wheeling." Questions at issue in defining wheeling in this case were:

1. Does the receipt and delivery of power by the wheeling utility have to be simultaneous to be considered wheeling?

2. Must power be transferred from one control area to another control area, neither of which is a part of the wheeling utility's control area, to qualify as wheeling?

3. Do the proposed contractual arrangements reflect payment for transmission services or other types of services?

III.4.1.2 Positions of the Parties

KU argued that transmission transactions must involve simultaneous receipt and delivery of power to be defined as wheeling and that the proposed transmission services did not meet this criterion. SEPA and cities took the position that contract wheeling such as the proposed arrangement came within the transmission services covered by PURPA. The Commission staff, however, agreed with KU that the service sought by SEPA did not constitute wheeling. Although the power might be delivered by KU to the cities simultaneously with receipt of the power from SEPA, the character of the delivered power would not be the same as that of the received power (a system resource) under the proposed contractual arrangement.

The proposed transaction would not involve the transfer of power from one control area to another, each independent of the wheeling agency's control area. because the cities are all located within KU's control area. However, as noted by staff, a legal precedent in the Otter Tail decision did not require that wheeling be from one control area to another.

SEPA proposed a billing arrangement under which SEPA would pay KU for transmission services provided and KU would give credit on its monthly bills to the cities by the amount of capacity and energy that could be received each month by KU. The Commission staff, in analysis of the transaction, concluded that the proposed crediting arrangement would be inconsistent with a wheeling transaction, because SEPA's proposal implied a difference between the type of power received and delivered. It presumed that the type of power being delivered to the cities would be peaking power. However, because of the availability limitations on the proposed transaction required by SEPA, KU could not always use the power at the time of its system peak or alter its generation construction plans because of the power. Thus, the power received by KU would not be peaking power from the standpoint of KU. The crediting arrangement being proposed by SEPA would be unrelated to the transmission service that would be provided in a transaction involving only wheeling. KU would also be receiving power from SEPA during periods of base-load demand and then be required to furnish peak-load capacity at times when SEPA would not be transmitting additional power. KU, in effect, would be providing an inventory service for a product that cannot be stored by adjusting its own rate of capacity utilization.

III.4.1.3 Judge's Recommendation

The administrative law judge found that the transaction proposed by SEPA, including the demand credit charges, did not qualify as a transmission service which would be subject to an order under subsections 211(a) or (b) of the Federal Power Act. Although SEPA was assigning 25 MW of power to the cities, there was an estimated realizable benefit of only 5,233 KW in reducing peak load requirements. The administrative law judge explained that "capacity, other than that to supply either base load or full requirements, cannot be transmitted to a customer not having generation sufficient to meet at least its remaining loads, and the ability to meter those loads constantly." Thus the value of the power SEPA transmitted was only a small fraction of the value claimed by SEPA and the cities. In effect, the judge decided that SEPA's proposal did not constitute a wheeling arrangement because "the character of the delivered power was not the same as the character of the received power."

III.4.2 PURPA Standards

III.4.2.1 Disputed Issue

Subsections 211(a) and (b) of the Federal Power Act provide means through which applicants may seek an order requiring an electric utility to provide transmission services to the applicant. Sections 211(a) and (c) specify a number of standards that must be met by affirmative findings before the Commission can issue a PURPA wheeling order. Among these standards are that any wheeling ordered must provide derived benefits "in the public interest" and must reasonably preserve existing competitive relationships. In addition, Section 212 spells out certain negative tests; that is, the Commission cannot issue an order unless it finds that the order would not result in certain harmful effects. At issue in this case is whether these PURPA standards have been met.

III.4.2.2 Positions of the Parties

SEPA and the cities claimed that the transaction would be "in the public interest," because the transaction would improve the reliability of electric service as a result of the increase in KU's system resources by 25 MW. KU maintained, however, that an increase in reserve capacity would not necessarily mean an increase in system reliability and that an additional reserve margin may not be needed. Additional potential benefits under Section 211 were argued by SEPA but disputed by KU.

KU also argued that existing competitive relationships would not be preserved because KU would lose to SEPA 18 percent of the power requirements and 6 percent of the energy requirements it was supplying to the cities. The cities, on the other hand, defined a much broader relevant market than just sales to the cities and argued that no significant change in KU's competitive position would take place.

The Commission staff maintained that each of the required findings (negative tests) could be met in this case, indicating that the proposed transaction was not shown by any part to "unreasonably impair the reliability of any electric utility affected by the order." The discussion of these requirements,

however, presupposes that the sought order meets the above mentioned criteria of potential benefit.

III.4.2.3 Judge's Recommendation

The administrative law judge recommended that no order to compel KU to provide the petitioned transmission services be issued. He held that while it had been shown that the requirements of Section 212 were satisfied, no showing had been made that the other requirements were met. Therefore, even if the proposed transaction were a proper subject for an order, SEPA's request should still be denied.

III.4.3 Commission Decision

The Commission rejected SEPA's wheeling request on the grounds that approval would not reasonably preserve existing competitive relationships, as required by FPA Section 211(c)(1). The intent of Congress, according to the Commission, was that this section protect a utility that is requested to wheel against the loss of sales to wholesale customers within its service area to other bulk power suppliers. The Commission made no findings as to whether the other PURPA standards were met or whether the proposed transaction constituted wheeling.

III.5 Florida Power and Light Company, Docket Nos. ER77-175 and ER78-19 (Phase II, et al.)

These cases involve a number of dockets in which wheeling services, as well as other electric power services, supplied by Florida Power and Light Company to certain municipal utilities located in Florida were at issue. The wheeling services were to be available to the following four interchange transactions:

1. Schedule TS, emergency service for periods of no more than 72 hours;

2. Schedule TB, capacity and energy for periods of less than 12 months;

3. Schedule TC, energy exchange of short duration, e.g., economy energy; and

4. Schedule TD, capacity and energy for periods of 12 to 36 months.

The initial decisions were issued on November 28, 1978, for Docket No. ER77-175 and on July 24, 1980, for Docket No. ER78-19. The major parties whose arguments will be discussed below are Florida Power and Light Company (FP&L), selected municipal utilities in Florida (cities), the Commission staff (staff), and Florida Power Corporation (FPC).

III.5.1 Joint Transmission Rate

III.5.1.1 Disputed Issue

If a wheeling customer requires wheeling services from both FP&L and FPC to effect a single transmission transaction, should a single joint rate be established rather than separate rates paid to each utility? In some cases for certain cities, a transaction requiring wheeling services from FP&L would also require wheeling services by FPC.

III.5.1.2 Positions of the Parties

The cities argued that FP&L and FPC should be required to file a joint rate because:

1. From a physical/engineering standpoint the two utilities actually operate as a single entity when performing wheeling services involving both systems;

2. The sum of the FP&L and FPC individual wheeling rates (as calculated independently) is in excess of the cost of joint service; and

3. Paying two separate rates puts the cities at a competitive disadvantage in competing with FP&L. The joint rate proposed by the cities would be less than half the sum of the two individual rates.

FP&L and FPC argued that a joint rate was inappropriate, because it would be non-compensatory, illegally subsidize joint-rate customers, and discriminate against their other wheeling and

nonwheeling customers. Staff, even though it did not object to the principle of a joint rate, did not support the cities' joint rate proposal, taking the position that the Commission cannot compel such a filing.

III.5.1.3 Commission Decision

The Commission rejected the cities' joint rate proposal on the grounds that:

1. It has no legal basis to compel such a rate unless the individual rates were unjustly or unreasonably high, a showing which was not made in this case;

2. There was no showing of competitive disadvantage to the cities; and

3. A joint rate would be discriminatory to other customers of the wheeling utilities.

III.5.2 Transmission Rate Base

III.5.2.1 Disputed Issues

The following two issues were in dispute regarding transmission rate base:

1. Should certain specific transmission lines or other facilities be excluded from transmission rate base when determining rates for wheeling customers?

2. Should a certain portion of total transmission plant be excluded from transmission rate base when determining rates for wheeling customers?

III.5.2.2 Positions of the Parties

With respect to the first issue, the cities argued in Docket No. ER77-175 that ten 240 kv radial lines connecting certain FP&L nuclear plants to the high voltage transmission grid should be eliminated from the wheeling rate base on the grounds that they serve a production related function and that certain other lines

should be excluded because they were specifically assignable to other customer classes. In Docket No. ER78-19. et al., the cities claimed that those facilities that FP&L considers transmission should be divided into three categories: bulk power supply, subtransmission, and production power supply. Then, only those facilities used to provide interchange transmission service (the bulk power supply category) should be included in the transmission rate base. The other two categories would not be included on the grounds that they are used to provide transmission necessary for wholesale requirements or retail power sales. The cities' proposal would have reduced FP&L's estimated transmission rate base by about 45 percent.

Concerning the second issue, the cities argued in Docket No. ER78-19 that the bulk power transmission system performs three functions: the transmission of power, the provision of transmission reliability, and the provision of generation reliability. Moreover, wheeling customers receiving firm transmission should not have that portion of the system performing a production reliability function included in the rate base, and wheeling customers receiving nonfirm service should have those portions performing the production reliability and transmission reliability functions excluded from the rate base. The cities calculated that 50 percent of the transmission system costs for firm customers and 77 percent for nonfirm customers should be excluded from the rate base. The same general argument was made in Docket No. ER77-175. except that the cities wanted to exclude only that portion of the system related to the production reliability function (alleged to be 30 percent) from the rate base.

FP&L used a so called rolled-in approach for determining the wheeling rate base under which all the transmission facilities were included in the rate base except for two minor categories:

1. In both dockets, facilities operated at 69 kv, if there were no present plans to increase their operating voltage, and

2. In Docket No. ER78-19, facilities at generating plant substations associated with stepping up voltages to transmission levels.

FP&L based its case for a rolled-in rate base on the fact that its transmission system is fully integrated and that the vast majority of wheeling transactions are accomplished by displacement. This means that wheeling transactions performed by FP&L affect power flows on the entire transmission system.

FP&L excluded 69 kv lines because its interconnections with wheeling customers are at voltages higher than 69 kv. The voltage step-up facilities were excluded because these facilities were not theoretically required to provide transmission only services.

Staff was in agreement with FP&L's general rolled-in approach, but disagreed on the exclusion of 69 kv lines and step-up transformers from the rate base. Staff argued that the 69 kv lines serve a transmission function by introducing FP&L power into the transmission grid, by providing primary power paths, and by providing secondary power paths which add to system reliability. Moreover, the step-up transformers also provide a transmission of power at higher voltage, which results in lower transmission line losses.

III.5.2.3 Commission Decision

The Commission accepted FP&L's rolled-in approach, as modified by the staff proposal to include additional facilities, such as the 69 kv lines, that were excluded by FP&L. The Commission's rationale for not excluding certain facilities totally from the transmission rate base, as proposed by the cities, was that in an integrated transmission system all of these facilities are involved to some extent in wheeling transactions, and therefore are properly included in the wheeling rate base. Moreover, they all properly come under the definition of "transmission function" contained in the NARUC Electric Utility Cost Allocation Manual. Several previous cases were cited as precedent for this longstanding Commission position.

The Commission also rejected the cities' proposal to functionalize the bulk power transmission system into three functions as being inconsistent with the rolled-in precedent. In addition, it was held that this approach had the following two intrinsic flaws:

1. The cities used this approach to determine responsibility for demand-related charges, whereas the relative responsibilities of customers receiving firm or nonfirm services are more properly addressed when an allocation of demand responsibility is made.

2. If one assigns a portion of the transmission system's reliability function to generation, the corollary assignment must also be made. This would assign some portion of FP&L's production facilities to the transmission function, because the reserve capacity of production facilities provides an alternate source of power in the event of a transmission outage.

III.5.3 Save Harmless Clause

III.5.3.1 Disputed Issue

Should the cities be required to indemnify FP&L against all claims from the parties involved in a transaction involving wheeling by FP&L, even if the claim arises out of the company's negligence or wrongdoing? The save harmless clause proposed by FP&L, which would grant blanket indemnification to FP&L against all claims, read as follows: "[The Customer] expressly agrees to indemnify and save harmless and defend FP&L against all claims, demands, costs or expenses arising out of providing the transmission service, including, without limitation, claims or demands asserted by [parties to the interchange agreement or any third party] in connection with the delivery of power to FP&L for [the Customer's] account."

III.5.3.2 Positions of the Parties

The cities did not oppose the inclusion of some form of save harmless clause but objected to the proposed language of FP&L because they believed the company should be responsible for claims arising out of the company's own negligence and wrongdoing. Staff did not object to the cities' position. FP&L claimed that blanket indemnification is necessary because the company has no control over the buyer and seller of interchange

power, and it might otherwise be held liable for any breakdown in arrangements between those parties.

III.5.3.3 Commission Decision

The Commission accepted the cities' argument, stating that there was no justification for FP&L's proposal and that the clause being required by the Commission would in no way subject FP&L to liability for actions by the buyer or seller of the interchange power.

III.5.4 Reactive Power Clause

III.5.4.1 Disputed Issue

Should a power factor clause specify a specific, rather than vague, power factor below which there will be a penalty, and should the exact nature of the penalty be specified? The following reactive power clause was proposed by FP&L: "[The Transmission Service Customer] shall be responsible for the supply of reactive power (MVAR) required on its own system and shall be responsible for the supply of reactive power required to maintain the power factor of the power delivered to [Customer] as near unity as practical."

III.5.4.2 Positions of the Parties

Staff objected to FP&L's proposed clause because it was vague as to what decrease in the power factor below unity (1.0) would violate the contract and what penalty there would be for a violation. Moreover, requiring a unity power factor of wheeling customers would force those customers to subsidize transmission losses incurred by FP&L in providing service to wholesale and retail customers that were not required to maintain a unity power factor. Both staff and cities supported a proposal that would require wheeling customers to maintain a power factor equal to FP&L's average transmission system power factor.

FP&L supported its proposal by stating that a high power factor increases its ability to transfer power and that supplying reactive power costs the customer less than taking power at a lower power figure. They also argued that the term "average

transmission system power factor" is without meaning and that other customers would be subsidized because FP&L, itself, attempts to stay as close to unity as possible by using capacitors.

III.5.4.3 Commission Decision

The Commission stated that both of the above proposals were flawed due to a lack of specificity and that neither one could be unconditionally approved. It was decided to allow FP&L's proposed clause to remain in the wheeling agreements but make it subject to the condition that FP&L make a section 205 filing with the Commission if and when it decides to invoke the provision.

III.5.5 Firm vs. Nonfirm Service and Responsibility for Demand Costs

III.5.5.1 Disputed Issues

Two issues of dispute related to the question of demand cost allocation were:

1. What constitutes firm wheeling service?

2. Should nonfirm wheeling customers be allocated any demand costs?

FP&L's wheeling service is offered on an "if and when available" basis in the sense that they can refuse to wheel at the time a request is made if there is insufficient transmission capacity. However, once a commitment is made to wheel for a certain period of time, the service is not interruptible, except for limited purposes, such as reliability or circumstances beyond the control of FP&L.

III.5.5.2 Positions of the Parties

FP&L maintained that all four of the wheeling services being offered were firm because once initiated they cannot be interrupted (except for limited purposes) during the period they are provided and that the services are properly allocated a portion of demand-related costs.

The cities and staff argued that the TA and TC wheeling services, which are provided only for short periods of time, should not be considered firm and allocated demand costs because FP&L can forecast accurately enough to refuse to provide service if there is likely to be a capacity shortfall during peak periods; thus, the company could avoid any new capacity costs associated with these services. Staff also argued that the same rationale should apply for TB wheeling service of one week or less.

III.5.5.3 Commission Decision

The Commission decided that none of the four wheeling services offered by FP&L, including the longer term TD service, could be categorized as firm service, because the company can refuse service at the time of a request; thus, customers have no assurance that they can receive service. However, even though the services were considered nonfirm, it was decided that it was equitable to allocate a portion of FP&L's demand costs to all four services. This was because the services do in a sense become firm once they are undertaken, and no matter how short the time period, FP&L is committed to using its transmission system for wheeling for that duration.

III.5.6 Method of Demand Cost Allocation

III.5.6.1 Disputed Issue

A third issue related to demand cost allocation was what method of demand cost allocation should be used.

III.5.6.2 Positions of the Parties

Cities advocated the use of a single coincident peak demand cost allocation methodology because they believed that the FP&L transmission load was very seasonal in nature; thus, use of an average of 12 monthly peaks methodology would artifically inflate the cost of wheeling. Also, the cities contended that their methodology would encourage off-peak use of FP&L's transmission facilities.

FP&L proposed allocation on the basis of an average of 12 monthly coincident peaks because this method provided for synchronization of rolled-in transmission costs and the demands placed on the transmission facilities during the same period. Moreover, FP&L believed that its load was sufficiently stable throughout the year to justify the use of this methodology, pointing out that the average monthly and lowest monthly demands during the test period were 88 percent and 77 percent respectively of the annual maximum demand.

Staff argued for the use of an average of FP&L's updated 12 monthly generation peaks (a noncoincident approach), adjusted for known transmission load. This was thought to be superior to FP&L's approach because of the difficulty of estimating transmission load, which would be required in the coincident peak approaches, and because of the additional accuracy realized by including known transmission load.

III.5.6.3 Commission Decision

The Commission decided to accept the staff's proposal. They reasoned that the use of either of the coincident peak approaches advocated by the cities and FP&L was impossible because of FP&L's inability to accurately estimate wheeling demand. Moreover, the use of a 12-monthly peak approach was considered justified by the relative stability of FP&L's load, and staff's addition of known wheeling transactions was thought to more accurately reflect total actual use of the transmission system and cost responsibility.

III.6 Pacific Gas and Electric Company, Docket No. ER76-532

This case involved the determination of the rate Pacific Gas and Electric Company (PG&E) should charge to wheel power for the Central Valley Project (CVP). The contract signed by PG&E and CVP in 1967 provided that rate disputes would be referred to the Federal Power Commission (now the Federal Energy Regulatory Commission) for resolution. PG&E filed for an increase in the wheeling rate from one mill per kWh to 1.7 mills per kWh in 1976, a rate that CVP felt was too high under the "fair and equitable" provision of the contract. Other agencies which

filed briefs for the initial hearing included the Northern California Power Agency (NCPA), the Arvin-Edison Water Storage District, the Department of the Navy, the Department of Energy (which succeeded the Secretary of the Interior), and the Commission staff.

The initial decision was issued on June 17, 1981, for Docket No. ER76-532. The Commission's opinion (Opinion 143) was issued August 16, 1982. Although the appropriate value of PG&E's cost of capital was a major point of contention in this case, the following summary will not address this controversy. This discussion focuses only on those issues which specifically relate to wheeling. The initial hearing and the Commission order both examined the choice of the most appropriate method for determining the transmission wheeling rate. There were a series of subissues which arose in choosing the method, and these are discussed below.

III.6.1 Delta Method Versus Cost of Service Methods

III.6.1.1 Disputed Issue

Should the wheeling rate have been based on DOE's Delta method, which is a fixed-formula calculation based on cost increases over the past five years, or on a detailed study of the cost of service? The Delta method would have required an estimation of the percentage increases in PG&E's costs of providing CVP with wheeling services between 1971 and 1976. This percentage would then be used to increase the previous rate of one mill per kWh to determine the new rate. CVP and DOE calculated that this procedure would result in a wheeling rate of 1.2 mills per kWh.

III.6.1.2 Positions of the Parties

In the initial hearing, CVP and DOE supported the Delta method as a procedure which would satisfy the contract's provision that the rates be "fair and equitable." Under DOE's interpretation of the PG&E-CVP contract's intent, the rate should reflect not PG&E's cost of service but the government's avoided cost of construction. DOE argued that the Delta method was a way to make those calculations. According to DOE, the Commission must look at this case as a contract dispute rather than a typical

rate case which would appropriately be governed by the traditional cost of service approach. The staff argued that the cost of service methodology should be employed in accordance with customary Commission practices.

III.6.1.3 Commission Decision

The Commission affirmed the argument of the administrative law judge in the initial decision that the use of the Delta method in this case was inappropriate. If the parties to the contract had intended the use of a specific "formulaic rate making method," it would have been included in the language of the contract. But Article 32 indicates that the agreement specified a more flexible approach which would consider the impact of various factors on cost. Therefore, the cost of service method should be applied.

III.6.2 Combined Versus Separate System Costing

III.6.2.1 Disputed Issue

Should the transmission system costs be calculated by considering the PG&E and CVP facilities as a single, combined system or should the transmission costs of PG&E be calculated separately, with appropriate credits being given to CVP on the facilities used by PG&E? This issue reflects the unique nature of the relationship between the PG&E and CVP facilities. There are a number of direct and indirect interconnections between the two systems in northern California. It has been common practice for power purchased or generated by PG&E to flow over the entire PG&E-CVP transmission system, commingling with CVP electricity. PG&E has the responsiblity of dispatching both its own and CVP power over the combined system.

III.6.2.2 Positions of the Parties

NCPA and the Commission's staff both argued that the combined system method was the most appropriate approach in this case. After determining the combined system cost, they advocated allocating that cost to PG&E and CVP based on their respective use of the transmission system. Staff and NCPA believed that this approach was the best way to account for the fact that the

transmission systems were operated in an integrated manner. Such an approach would also insure that CVP would not in effect be charged for PG&E's use of its own transmission lines.

PG&E and CVP opposed the implementation of the single-system viewpoint. PG&E based its argument on two factors. First, the two systems were not built to operate as a single entity. There were redundancies in the system which would not have been built if the transmission lines were planned as one system. Secondly, PG&E could operate independently of the CVP system without a dramatic loss of reliability. PG&E argued that its use of the CVP system did not provide any material benefits. CVP based its argument against the combined system method by pointing out that the two systems are separate, if interdependent, in the language of the contract. PG&E was not given the right to use CVP's lines. If PG&E did happen to use CVP's transmission facilities, this action was to be interpreted as an "inadvertent flow" not subject to compensation.

III.6.2.3 Commission Decision

The Commission agreed with the administrative law judge's argument that the wheeling rate should be determined using the traditional cost of service analysis, with credits being given to CVP based on the system's integration. In the initial decision, the ALJ pointed out that the combined system method would result in the customers of PG&E paying higher transmission rates and, in effect, providing a subsidy to the customers of CVP. The judge affirmed PG&E's arguments that although the two systems were interrelated and coordinated in operations, construction planning was independent, and PG&E could operate without the CVP facilities (although CVP could not operate independently of PG&E).

III.6.3 Calculation of Credits

III.6.3.1 Disputed Issues

Given the adoption of PG&E's cost-less-credit method for calculating the appropriate wheeling rate, the parties were not in agreement over what constituted an appropriate credit. The initial decision included a discussion of a list of

credit-calculation options, including the functionalization of transmission costs, incorporation of PG&E's underground lines to San Francisco in the transmission rate base, revenue credits, the use of actual net flows for allocating costs, synchronization of interest expense, a generation-tie equivalent credit, and tax adjustments. The Commission simplified the credit issue into an examination of the four credit proposals made by PG&E:

1. A 100 percent credit for generation taps constructed to bring the wheeled load from CVP to PG&E (estimated value of $1.85 million of depreciated capital).

2. A 49.9 percent credit (where 49.9 percent is the share of the total kWh of power generated by CVP which is wheeled) for the connections at the powerhouses located at Spring Creek, J.F. Carr, and Trinity (estimated value of $1.98 million of depreciated capital).

3. A 100 percent credit for possible future use of CVP's "Eastside" line (estimated value of $3.07 million).

4. A 5 percent credit for all of CVP's transmission facilities reflecting the intangible reliability benefits accruing to PG&E and not accounted for in the other allocations (amounting to an estimated $1.5 million).

III.6.3.2 Positions of the Parties

PG&E argued that the cost of generation ties should not be charged to wheeled loads. Therefore, PG&E proposed that credits (1) and (2) be established to adjust for this cost element. CVP, however, argued that a credit was not the best way to handle this issue. Counsel for CVP presented an alternative approach in which the generation ties would be removed from the transmission rate base.

In testimony recorded after the original filing, PG&E argued that credit (3) should be abandoned because anticipated load growth did not materialize. PG&E did not have plans to use the "Eastside" line until well into the 1980s. Therefore, PG&E should not be required to give a credit for facilities not

actually used. This argument was not rebutted by CVP. PG&E also presented arguments to the effect that since the CVP transmission facilities were not required for the smooth operation of the PG&E system, there should be no credit for CVP's possible enhancement of system reliability.

III.6.3.3 Commission Decision

The Commission affirmed the initial decision ruling to adopt credits (1) and (2). The administrative law judge observed that since CVP's argument by counsel did not constitute sufficient evidence for the proposal to exclude the generation ties from the rate base, the credit procedure proposed by PG&E should be adopted. The Commission agreed that the "Eastside" credit was no longer appropriate. However, the Commission ruled that the reliability credit should be adopted. The Commission felt that despite PG&E's studies to the contrary, the PG&E system received an intangible benefit from its linkage with the CVP system.

Other credits that had been proposed by the parties involved in the proceedings were rejected by the Commission, supporting the arguments made in the initial decision.

III.6.4 Rate Design

III.6.4.1 Disputed Issue

Should rates be based on an energy charge (mills/kWh) or a demand charge (cents/kW)?

III.6.4.2 Positions of the Parties

The Commission staff suggested that the wheeling rate be changed to a cents/kW rate because the costs of wheeling are dependent upon maximum load factors. Costs are therefore more appropriately estimated on a demand allocation basis. Staff also contended that the switch to the kW-based rates need not alter revenues. PG&E and CVP both argued for a continuation of the energy charge. PG&E presented evidence that the kWh-based method allowed for a more accurate reflection of the cost of service.

III.6.4.3 Commission Decision

The administrative law judge ruled that the wheeling rate should continue to be formulated in terms of an energy charge. The parties had agreed to the kWh-based rate in the original contract and had been using such a rate for nearly 30 years. The ALJ felt that the staff's argument for changing to the demand rate was unconvincing. The Commission concurred.

III.7 Limits for Percentage Adders in Electric Rates for Transmission Services, Order 84, Docket No. RM79-29

Questions concerning escalating energy costs and fairness in the use of percentage adders were raised following the economic upheaval created by the oil embargo and a coal strike in the 1970s. Percentage adders were incremental charges tacked on to the purchase price of power. The Federal Energy Regulatory Commission (Commission) coal strike report in 1979 showed how "added charges may be compounded several times in a single interchange transaction without regard to the actual internal incremental costs incurred by each intervening utility."[1]

The Commission issued a Notice of Proposed Rulemaking on April 4, 1979, to establish limits for all percentage adders in electric rate schedules. The Commission received comments in the rulemaking process from 90 public utilities and cooperatives, six power pools, 16 municipal, state, and federal entities, and three trade associations. Sixteen commenters, including the Commission staff, appeared before the Commission in hearings on June 4, 1979. The final rule was issued in Order No. 84 on May 7, 1980.

The Commission's rule requires that revenues be limited to one mill per kilowatt-hour or less in percentage adders which are part of rate schedules used in the "transmission or third party resale of electric power." A percentage adder is defined as: "a

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1. Report of the Designated Officer, Investigation Into Wholesale Power Transactions During Time of Fuel Inadequacies, March 19, 1979 (Docket No. ER78-367). The discussion of adders is found on pages 11-14 and Appendix I, pages 7-13.

rate component that recovers revenues computed wholly or in part as a percentage of the price of purchased power paid by a transmitting utility for power generated by another utility." The rule also requires "submittal of cost information to support the limits that are established for percentage adders used by a transmitting utility." If the utility's percentage adders are limited to one mill per kilowatt-hour or less, cost information is not required. The comments and the issues discussed in the final rule are summarized below.

III.7.1 Authority of the Commission to Establish Rates

III.7.1.1 Disputed Issue

Does the Commission have the authority under existing legislation to establish rates by rulemaking procedures?

III.7.1.2 Positions of the Parties

Potomac Electric Power Company (PEPCO) and other commenters challenged the authority of the Commission to establish rates by rulemaking procedures as proposed. PEPCO argued that Section 403(c) of the Department of Energy Organization Act (DOE Act) did not give the Commission greater authority than that authorized by the Federal Power Act and, therefore, the Commission did not have the authority to issue a rule on rates. The Commission staff replied that the Commission may exercise "its discretion to establish just and reasonable rates by rule" under both the DOE Act and the Federal Power Act.

III.7.1.3 Commission Ruling

The Commission agreed with the staff that the DOE Act did establish a procedure whereby the Commission may decide on the "justness and reasonableness of rates on a generic basis, independently of strictly adjudicatory proceedings." The Commission's opinion was that rulemaking is an appropriate tool when a feature common to the entire industry is found to lead to undesirable effects.

III.7.2 Use of Adders for Cost Recovery

III.7.2.1 Disputed Issue

What purposes are served and what costs should be recovered by the use of percentage adders in rate schedules?

III.7.2.2 Positions of the Parties

The Commission's preliminary position in the hearing was that the use of percentage adders in electric rates should be strictly limited to recovery of incremental costs that are either too difficult or too expensive to quantify. Adders were not designed for the recovery of fixed costs or a return on investment.

The commenters, on the other hand, described the utilities' use of percentage adders as "compensation for fixed costs, incremental costs, risks taken by the generating utility, or error in the estimation of costs." Several commenters viewed percentage adders as an "incentive to engage in interchange transactions" or some form of compensation beyond those costs that are fully allocated.

III.7.2.3 Commission Ruling

The Commission ruled that the use of percentage adders based solely on the purchased power price cannot be cost justified. The Commission accepted the fact that a limit of one mill per kilowatt-hour can "usually be cost justified." Therefore, the final rule permits the use of percentage adders up to this limit without cost justification. Percentage adders in excess of the limit are permitted subject to adequate cost justification.

III.7.3 Scope of the Rule

III.7.3.1 Disputed Issue

Should the rule apply to both generating and transmission utilities?

III.7.3.2 Positions of the Parties

The proposed rule would have established limits for all percentage adders in electric rate schedules. Several of the commenters suggested that the rule might appropriately be applied to transmission utilities. This would, they argued, "reduce unreasonable costs to the purchasing utility."

III.7.3.3 Commission Ruling

The Commission concluded that the final rule applies to those utilities involved in the "transmission or third party resale of electric power." The Commission's ruling was predicated on the recognized "functional difficulties raised by the use of adders by transmitters in multiple, as opposed to bilateral, interchange transactions." The Commission asserted that it will continue to study the use of percentage adders by generating utilities.

Appendix IV

Institutional Aspects of Wheeling Arrangements

Special institutional aspects of the relationship between utilities, can have influences on the appropriateness of the terms and conditions in the wheeling arrangements. It will be argued in this appendix, however, that these institutional aspects are minor with perhaps the exception of centrally dispatched power pools. All other institutional aspects can be considered minor variations of normal relationships between utilities. The different institutions that will be discussed in this appendix are: (1) power pools; (2) holding companies; and, (3) federal marketing agencies.

IV.1 Power Pools

There are basically three types of power pools. The first type is composed of closely coordinated power pools in which generation is centrally dispatched and planning is determined by a central body. This means that all decisions as to power production is controlled by the pool. The actual generating plants are operated by the individual utilities but decisions as to how much and when those plants produce power are controlled by the pool. Centralized dispatching means that the lowest cost plants are operating and the cost of power production in the area is minimized. Reliability is also increased since power generation is not centralized in a few plants. Finally, coordinated planning ensures that the most efficient plants are built in a region at the appropriate time. The pools in the Northeast, such as NEPOOL, NYPOOL, and the PJM Pool are representative of this type.

The second type of power pool are moderately coordinated power pools. This type has a brokerage system to determine generation, and performs some centralized planning. In this type of systems offers to buy and sell power are received by participating utilities, usually hourly, and matches are

performed for power exchanges based on some agreed upon formula. Most of the advantages of a closely coordinated pool can be captured by such systems. The Florida Power Pool is an example of this type.

The final type is composed of loosely coordinated power pools, which have various methods of determining power exchanges and perform some centralized planning. How well they approach achieving the advantages obtained by closely coordinated pools, depend on their degree of coordination.

The stated objectives of all pool types is to minimize power production costs through the use of bulk power transfers. Therefore, they are consistent with the reasons given for the promotion of wheeling by utilities.

The wheeling arrangements of power pools, studied in Appendices I and II, are similar to those between other utilities with the exception of compensation methods, and notification requirements in centrally dispatched pools. The compensation methods used in some centrally dispatched pools are radically different from other wheeling arrangements. NEPOOL does not charge for wheeling services for economy power sales, and, until recently PJM did not charge for wheeling services for any type of power sales. NYPOOL, rather than charging for the service, gives 9.2 percent of the pool's savings to bulk transmission line owners. For all of these pools, the price mechanism or costs do not influence decisions on wheeling services.

This situation may lead some to allege that without the price mechanism too much wheeling services are being demanded and without cost based rates too little or too much wheeling services are being supplied dependent on the degree of compensation for transmission services. However, the individual utilities do not make decisions on wheeling services, but rather, the power pool through their decisions on power generation and capacity planning. The costs of transmission should be and are considered, therefore, in the pool's cost minimizing decision process.

Another problem is the vast amount of wheeling transactions that are made in highly centralized pools. It may be difficult to

quanitify the costs involved in all the wheeling transactions that may occur. In conclusion, in the case of power pools, the compensation methods may be justified.

The second major difference between power pool wheeling arrangements and other arrangements is in the notification areas. Usually, notification requirements state that normal dispatching procedures are to be used. In centralized pools, all power flows are controlled by the pool itself, so notifications usually are not necessary.

IV.2 Holding Companies

A number of utilities in the United States are organized into holding companies. A utility holding company is a company where one overall umbrella company controls a number of other companies, sometimes referred to as operating companies. The umbrella company usually does not sell power directly to retail customers but is responsible for overall management, joint-coordination, and planning for all of the operating companies. In some cases, all power production is the responsibility of one subsidiary while retail power sales may be the responsibility of the other subsidiaries. Usually, the operating companies are organized on the basis of the state in which they are located. For example, if a company is operating in three states, it may form operating subsidiaries in each of the three states. Since regulation of retail sales of investor owned utilities is at the state level, regulation is made much easier under this type of organization.

Holding companies are similar to power pools in that generation and capacity planning are centralized in the company. The individual subsidiaries usually do not have authority in these decisions. Therefore, they are not influenced by charges for wheeling services. The costs of transmission, therefore, should be considered at the level that decisions are made, that is, at the holding company level.

IV.3 Federal Marketing Agencies

Federal Marketing Agencies are identified and their wheeling arrangements described in Appendix I of this report. There is little difference between their wheeling arrangements and those of others with the exception of the higher incidence of tariffs and simpler rate schedules. In contrast to investor owned utilities, there is little regulation of the Agencies. Their wheeling arrangements only have to be in the "public interest", that is, they have to return the public's investment. No compelling reason was found that there should be special differences between the Marketing Agencies' wheeling arrangements and those of other entities.

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