Review of Cost of Service Issues

Final Report

Manitoba Hydro

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APPENDIX IX

TO QUESTION E(b)

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I. INTRODUCTION

Ernst & Young was engaged by Manitoba Hydro to provide analysis, advice and recommendations with respect to the following four cost of service methodology and application issues:

- Classification of generation and transmission functions between demand and energy parameters
- Allocation of demand-related generation and transmission costs among customer classes
- Classification of distribution function into demand and customer parameters
- Definition of a "customer" and its appropriate cost of service weighting within the streetlight class of service.

This report presents the results of our review.

BACKGROUND

Traditional utility rate design proceeds from a three-step process whereby costs are allocated to customer classes. The three steps are:

- Functionalization
- Classification
- Allocation.

Functionalization separates utility plant and expenses into broad categories according to the function performed, e.g., generation, transmission, distribution. Classification is the separation of costs into major categories or classifications. Typical classifications are customer, energy, and demand. Allocation spreads classified cost among the utility's customer classes, which are groups of customer with similar usage characteristics or service requirements. The allocation process uses class characteristics that comport with the classification of the cost: customer costs are allocated based on a weighted or unweighted count of the number of customers in each class; energy costs are allocated based on the weighted energy consumption by each class; and demand costs are allocated based on the weighted demand of each class.

Utilities generally are required to set rates so that revenues will equal the utility's cost of providing service, including a reasonable return on the utility's investment. This matching of the revenue requirement to the cost of service frequently reflects the utility's obligation to serve consumers and the utility's exclusive franchise to serve consumers.

Utilities set different rates for different customer classes and serve a diverse mix of customers. Customer service requirements may cause the utility to incur costs in differing proportions for different customers. As the utility incurs differing costs, matching revenues with expenses suggests different rates for different customers. Since it is impractical to set a different rate for each customer, utilities group customers together into classes, determine how class characteristics cause different costs to be incurred, and then set rates to recover revenue from the class equal to the costs incurred for the class. This process was recently described by the Massachusetts Department of Public Utilities:

> The rate-making cost allocation process comprises five tasks: (1) functionalization, or the grouping of costs by function (costs are defined as being related to the production, storage, administrative, or transmission and distribution function of providing service); (2) classification (costs are classified as demand, energy, or customer related); (3) the determination of

an allocation factor for each classification within each function; (4) the allocation of costs among rate classes, based upon the cost groupings and the allocators chosen, and the summation of the allocations by rate class to determine the cost of service for each rate class; and (5) a comparison of the cost of service with the level of revenues for each rate class; if the level of costs closely matches the level of revenues, the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each class pays the cost of serving it; however, if the differences between the allocated costs and revenues produced are great, then for reasons of rate continuity, the revenue increase or decrease may be allocated in a manner that will reduce the difference in rates of return in a more gradual fashion. (Re Boston Gas Co., 96PUR4th538(1988).

This report focuses on the second and third of the five tasks specified above. The first task, functionalization, is assumed to follow the books and records of the Corporation with the Corporation identifying two major functions: Production and Transmission, sometimes referred to collectively as Bulk Power Supply, and Distribution. The fourth task, allocation, is a mechanical application of the third task. The last task, a comparison of revenues and cost, has been addressed in another report.

Class cost of service studies are performed under two sets of potentially conflicting assumptions. Embedded class cost of service studies enumerate the cost components of the revenue requirement and identify a feature that causes the cost to be incurred. Based on a count, a measure, or a calculation of the cost causative element, the cost component is then allocated to customer classes. This allocation process is used for every component of the utility's revenue requirement. The driving concept of embedded cost of service studies is equity. If the utility incurs costs because of a group of customers, that group of customers should pay for the costs.

Marginal class cost of service studies identify the additional costs that a utility will incur as the result of an increase in customer consumption. These additional costs will generally include each of the components of the revenue requirement. Marginal cost studies strive for economic efficiency, which requires that customers be shown, via rates, the cost impact of their consumption of additional services.

Classification and allocation methods reflect the cost of the systems and current regulatory environment. The effect of a changing regulatory environment on classification and allocation methods was summarized by the U.S. Federal Energy Regulatory Commission in a gas transmission case:

> The Federal Energy Regulatory Commission has allowed various rate designs on different pipeline systems and historically has shifted fixed costs back and forth between the demand and commodity components of wholesale rates to achieve an appropriate balance of changing regulatory goals; the strait fixed-variable method of assigning all fixed costs to the demand component is justified only in rare instances because there is no economic reason to assure pipeline profits when sales are not made. (Re Natural Gas Pipeline Co. of America, 37 FERC Para. 61,215, 79 PUR4th209, Opinion No. 256 1986).

These changes in methods also occur in the state regulation of electric rates. We will present contemporaneous orders of the North Carolina Commission that order the application of different allocation procedures for the various utilities under its jurisdiction. The Wisconsin Commission decided to use several methods in one case:

> All the various embedded and marginal cost studies presented in he proceeding will be utilized in allocating class cost responsibility, because although they all have some value, none of them is accurate enough to establish the precise cost of providing electric service to any class. (Re Madison Gas & Electric Co., 3270-UR-100, May 29, 1986.)

In some respects, selection of classification and allocation methods becomes a sorting of ideas, eliminating those that are currently least acceptable, retaining whatever is left.

CONTENTS OF THIS REPORT

The remainder of this report is organized into four chapters as follows:

- Chapter II - Classification of Generation and Transmission
- Chapter III - Allocation of Demand Related Generation and Transmission Cost
- Chapter IV - Classification of Distribution Costs
- Chapter V - Customer Weighting for Street Lighting

Several appendices are provided at the end of this report which summarize relevant commission orders and show a statistical allocation example.

II. CLASSIFICATION OF GENERATION AND TRANSMISSION

INTRODUCTION

In its current rate filing, Manitoba Hydro classifies generation and transmission as 42% demand-related and 58% energy-related on the basis of system load factor for domestic sales. The Company does not directly classify any specific plant or expenses as purely demand or energy related. This chapter reviews the classification practices of other regulatory jurisdictions in the context of Manitoba Hydro's system operations to determine if Hydro's current classification method is appropriate.

SEPARATION OF GENERATION AND TRANSMISSION

Generation refers to the production of electricity in a power plant, generally using steam or falling water to turn a turbine that is connected to a generator. Some systems also use combustion turbines, diesels, and windmills. Manitoba Hydro primarily uses falling water to produce electricity, with some steam powered generation and some isolated diesel units. Transmission refers to the movement of electricity from centralized production locations to centralized distribution points, distribution stations that reduce the potential of the electricity to lower voltages. The generation and transmission functions are often referred to collectively as power supply.

Generation and transmission systems must be planned on a coordinated basis. As customers consume more electricity, the utility must increase its generation capability. The selection of generation plants depends on the total cost of providing electricity to the customer. Low cost generation that requires higher transmission costs may not provide the bargain originally anticipated. Coördinated planning of generation and transmission systems can lead to a uniform classification of the cost of the two functions.

The uniform treatment of generation and transmission costs was explicitly adopted by the Washington Utilities and Transportation Commission:

> Electric transmission plant should be classified between energy and demand components on the same basis as electric production plant, because some transmission plant is required by the construction of geographically remote baseload plant. (Washington Utilities & Transportation Commission v Washington Water Power Co. Cause Nos. U-82-10, U-82-11, Dec. 29, 1982.)

Other commissions implicitly adopt the same methodology for both generation and transmission. However, at least two commissions have looked at transmission as separate and distinct from generation. The Maryland Public Service Commission found for a pure demand classification for transmission:

> The capacity of a transmission line is determined by peak demands and is demand related; evidence indicates that supplying load, rather than energy savings or transfers, is the primary consideration employed by the utility's system planners in planning a transmission system, therefore, to classify the utility's transmission investment as demand related rather than energy related is appropriate. (Re Delmarva Power & Light Co. 75 Md PSC 598, Case No. 7829, Order No. 66884, Dec. 19, 1984.)

The New York Public Service Commission also took this position for similar reasons:

> A secondary allocation for 20 percent of the share of marginal transmission costs of each class to off-peak season was rejected as

> unjustified because allocation of all transmission costs to the peak (on-season) period reflected more closely the difference between the types of plants used as accentuated by the summer peaking nature of the utility's load. (Re Consolidated Edison Co. of New York, Inc. (1983) 53 PUR4th 96, Opinion No. 83-6.)

However, neither order would preclude the joint consideration of generation and transmission.

Some commissions look at the transmission system as a system of discrete, separately allocable components. Other commissions treat the system as an integrated whole. Interestingly, the Idaho commission has taken both positions. In one case, the Commission reasoned that the low voltage transmission system provides backup to the high voltage transmission system and should be jointly allocated:

> The commission found that it is appropriate for the utility company to roll in its low-voltage transmission facilities with its high-voltage transmission facilities in its firm class cost-of-service studies when the evidence is clear that the company's lower voltage transmission system is capable of providing backup support for serving high-voltage facilities because of the integrated nature of the company's system. (Re Utah Power & Light Co. (1984) 63 PUR4th 13.)

This would support Manitoba Hydro treating its DC line in the same way as the rest of Hydro's transmission system. In a contemporaneous case, the Idaho Commission identified separate losses for wheeling loads that went outside the state:

> The commission accepted a jurisdictional allocation factor that adjusted for transmission losses for the Washington-Idaho jurisdiction power interchange, finding that the effect of not including transmission losses in this interchange was to assign transmission losses from this net power flow into Washington entirely to the Idaho jurisdiction, and rejected as unpersuasive the utility's argument that a change in the jurisdictional allocation factor should be delayed until its next filing because hearings before the Washington commission had been completed since the company was not precluded from requesting modification of its jurisdictional allocation factors in other jurisdictions. (Re Washington Water Power Co. (1984) 58 PUR4th 126.)

Appendix A contains a selection of regulatory citations on the classification of generation and transmission cost.

ISOLATED GENERATION

In many parts of the world, electric utilities began with the installation of small generators serving a local distribution system. The capacity of the installed generators was selected based on the maximum anticipated demand of the distribution system, with appropriate allowances for reliability through a reserve margin above the anticipated demand. Production plant staffing depended on the number of generators, and to a lesser extent, on their size. Fuel use depended on the energy used by consumers. This situation is similar to the current one in which Manitoba Hydro serves isolated locations with diesel generators.

The classification of costs should follow the way the utility incurs costs at these isolated locations. Fuel costs are classified as energy related and remaining costs, including investment related costs, such as labor, are classified as demand related. This classification system for the cost of isolated production facilities is straightforward and reflects a simple view of cost causation.

A marginal view of costs may result in a slightly different classification of costs:

- The choice of generating capacity frequently involves tradeoffs between installed cost and fuel cost. Less expensive fuels frequently require more complex generators with a higher installed cost. Such a choice would indicate that some fixed costs are incurred to lower variable costs. Accordingly, a portion of the fixed costs should be classified as energy related instead of demand related.

- Maximum demand frequently determines the fuel cost during minimum system conditions. A generator operating in idle incurs an hourly fuel cost roughly proportional to its size. This idling fuel penalty will depend on the maximum load the generators are expected to carry. Accordingly, a portion of the fuel costs should be classified as demand related instead of energy related.

- Energy costs differ by time of day. In addition to idling fuel, a generator burns some fuel for low levels of electricity production. Greater levels of production naturally require higher levels of fuel consumption. Less obvious is the increasing amounts of fuel required to produce uniform changes in production. Because of this phenomenon, a unit of electricity at night will change fuel costs less than a unit of electricity used during the day.

- Cycling generating plants increases the cost of maintenance and the cost of fuel. Meeting both daily peak demands and daily minimums requires generating plants to cycle, increasing fuel flows and temperatures during high load periods, decreasing fuel flows and temperatures during low load periods. This produces thermal stress, resulting in increased degradation of the generating unit and inefficient conversion of fuel into electricity. Some fuel costs should thus be classified as demand-related.

These different techniques for classifying production costs are still being developed.

TRANSMISSION LINKS BETWEEN ISOLATED PRODUCTION SITES

As electric utilities expanded their operations in adjacent communities, planners realized economies of scale existed. Larger generators had lower unit installed and operating costs. Doubling the size of a generator increased installed cost by about 60%, lowering unit cost by 20%. This doubling of size frequently could be achieved without a change in the actual number of employees. Thus, non-fuel operating costs would drop 50% in comparison to the unit's capability. These economies could be achieved by local load growth or by consolidating the operations of neighboring electric systems.

The cost of building a transmission system to link these isolated sites would provide a benefit of lower installed cost of production, which is demand related; a lower number of production employees, whose salaries are demand related; and a slight reduction in fuel cost through the use of more efficient generators, an energy related savings. Because the predominant savings achieved by the installation of transmission between isolated generation locations is demand related, the cost of transmission networks was generally treated as demand related. This rationale was the basis for the Maryland Public Service Commission making the previously identified finding in the Delmarva Power case.

Larger systems also resulted in diversity savings. Local networks generally peak at different times. Adding several networks together results in a consolidated network with a peak demand that is less than the sum of the peak demands of the individual local networks. This also reduces the demand related cost of production with only a minor effect on energy related costs. Thus, transmission lines provide the diversity benefits of lowering demand related production investment. This furthers the concept of treating transmission costs as being demand related.

INTEGRATED SYSTEM PLANNING

Larger networks allow electric companies to take advantage of competing technologies for producing electricity. Coal fired steam units can be built in almost any size desired, from a few MW to 1300 MW. The economics of coal fired steam units change dramatically with size. In contrast, the economics of diesel units change minimally with size. Accordingly, small systems will install diesel units that have low installed costs and high operating costs. Larger systems will install coal fired steam units with lower operating costs to meet year round loads, and diesel units to meet short term peaking needs.

Systems with competing production facilities have used several different methods to classify costs. The simplest classification method continues the classification of fuel costs as being energy related and the classification of the remaining production costs as being demand related. This classification scheme is often used with an allocation method that includes energy as a component of the allocation factor. An alternative method classifies a portion of the non-fuel costs as energy related, the most frequently stated portion being derived from the system load factor.

Marginal cost analysis has produced additional methods for classifying production costs. The peaker method uses the unit cost of a peaking unit (such as a diesel or gas turbine) to determine the amount of demand related production costs. The remaining costs are classified as energy related. A base fuel method uses the unit fuel cost of a base load generator to determine the amount of energy related costs. All other fuel costs and other production costs are classified as demand related. Marginal cost theory also presents two methods for time-of-use cost classification, long run and short run.

Long run marginal cost analysis assumes that the current stock of production plant is replaced with the optimal stock of production plant. The optimal stock is determined with regard to the system load curve and to the cost of the various inputs, i.e., the installation cost of potential types of generators, fuel cost of appropriate generation, and other operating costs. Resource limitations are acknowledged for fuel, hydroelectric sites, and annual water flows. Marginal costs by time period are the unit change in cost per change in the system load curve. Unit costs are determined for all 8,760 hours of the year, plus a unit demand charge. Generally, the unit demand charge is the fixed cost of a peaker, such as a diesel. The presence of a substantial amount of hydroelectric capacity can affect this generality. Marginal costs times consumption produces total classified energy cost by time period.

Short run marginal cost analysis assumes that the current stock of production plant is fixed, except for the potential to add a peaking unit to meet marginal peak period demand. The existing production plant is dispatched to meet the system load curve in an optimal manner, with due consideration to the fuel cost of available generation and to resource limitations. Marginal costs by time period are the unit change in operating costs (primarily fuel) per change in the system load curve. While long run marginal cost analysis allows a tradeoff between fuel costs and fixed capital and operating costs, short run changes in consumption can only be met by increased operation of existing capacity. Marginal cost times consumption produces total classified energy costs by time period.

Marginal demand classified costs will be dependent on the system planning criteria adopted by the utility. Planning criteria include:

- Planned reserve as a fraction of planned peak demand - required capacity would be peak demand times an appropriate reserve multiplier.
- Planned reserve as a fraction of average peak demand - demand classified costs are based on an average of three to twelve monthly peaks, instead of a single peak
- Loss of load probability - the amount of capacity is determined by the criteria adopted by the utility, the annual load curve, and the availabilities of the utility's generators.

Demand related production costs would be the above capacity times the economic carrying costs of a peaking unit.

Generally, total classified cost using a marginal cost approach will be significantly different from the production revenue requirement. Several approaches have been used to reconcile classified costs to revenue requirement:

- Equal percent of marginal cost for all functions - after all costs by function have been classified, each set of costs is scaled uniformly to meet the utility's revenue requirement.

- Equal percent of marginal cost by function - classified costs for a function are scaled uniformly to meet the functional revenue requirement, each function standing alone.

- Ramsey pricing by classification - classified costs are adjusted inversely to their elasticity. Changes in energy prices are more likely to influence consumption than changes in demand or customer prices. Accordingly, customer costs are varied most from marginal cost and energy costs are changed the least.

- Ramsey pricing by customer class - after allocation to customer classes, residential and street lighting rates are altered most from marginal costs because these customers are least likely to vary their consumption as a result of price changes.

Equal percent of marginal costs is generally advocated as being more equitable (not obviously favoring a particular class). Ramsey prices favor particular classes but are believed to promote economic efficiency.

REMOTE HYDROELECTRIC GENERATION

Manitoba Hydro has hydraulic resources available that can be used for hydroelectric generation. Manitoba Hydro's investment in these resources and in the transmission lines necessary to connect the generation to Hydro's backbone transmission grid provides a benefit equal to the cost of the thermal resources Hydro might otherwise install. The classification of such an alternative thermal resource provides an appropriate basis for classifying the cost of the hydroelectric facility and transmission line.

Any cost reduction from the alternative cost can be classified either as a demand reduction, an energy reduction, or shared between the two classifications. The difference in dispatch order between a hydro unit and thermal capacity suggests favoring the energy classification with a disproportionately greater reduction.

Consider a hydroelectric project that will generate a revenue requirement of $100 million over its expected life. The project replaces various thermal resources whose revenue requirements would have been $120 million over the same time frame. The $120 million would have been classified as: $70 million for demand; and $50 million for energy. The hydroelectric project produces costs savings of $20 million. These savings can be used to reduce demand classified costs to $50 million, to reduce energy classified costs to $30 million, or be split between energy and demand. A proportional split results in demand costs of $58.3 million and energy costs of $41.7 million.

The Texas Commission advocated a fixed-variable approach to classify costs:

> In a cost of service study in an electric rate case, the costs that are classified as demand-related are those costs associated with the fixed plant investment and expenses required to meet the maximum kilowatt demand placed on the system by the various customers; the amount of system demand determines the size of a utility's production, transmission, and distribution facilities that must be capable of meeting customer needs at the time and levels required. (Re Houston Lighting & Power Co., -Tex PUC Bull-, Docket Nos. 6765, 6766, Nov. 14, 1986, modified Dec. 4, 1986.)

In this case, fixed costs, almost the entire cost of a hydroelectric plant, are classified as demand related and variable costs, generally insignificant on a hydroelectric system except for water rentals, are classified as energy related. For another utility, the Texas Commission went further by classifying some fuel costs as being demand related:

> For rate-making purposes, nuclear fuel in process and fuel stock inventories should not be allocated entirely on the basis of the energy component of a customer's bill; they should be allocated on a 50-50 basis between energy and demand components. (Re Dallas Power & Light Co. 9 Tex PUC Bull 440, Docket No. 5256, Jan. 12, 1984.)

Thus, the classification of costs ranges from being entirely energy related to treating all fixed costs and some variable costs as demand related.

Manitoba Hydro has adopted a middle ground for classifying production and transmission costs, using system load factor to set the percentage of costs to be classified as energy related, with all remaining costs classified as demand related. This approach is consistent with the popular "allocation" method, average and excess demand, which both classifies costs and allocates costs in one procedure.

INTERSYSTEM TRANSACTIONS

Manitoba Hydro is interconnected with other utilities, and uses these interconnections to buy and sell electricity under appropriate conditions. These transactions with other utilities provide information about the marginal cost of electricity on a basis more global than just the Province of Manitoba. These marginal costs provide an alternative definition of marginal energy and demand costs for classifying Manitoba Hydro production and transmission costs. This definition of marginal costs may be more tractable than one calculated purely from Manitoba Hydro system costs. The relatively small amount of thermal generation compared to hydro generation will generally provide an inadequate marginal cost signal.

England and Wales are now facing the use of extrasystem costs to determine the classification of generating costs. The Central Electricity

Generating Board (CEGB) owns the electric generation capacity in England and Wales. CEGB uses its hourly marginal fuel costs to determine energy costs. All other production costs are demand related. Under privatization, CEGB will be split into two entities, with each entity competing to sell electricity to local distribution boards. The generating entities will sell system supply power or commit specific units to specific distribution boards. Accordingly, each distribution board will have available a different mix of generation with a different profile of energy costs. Despite these differences, the distribution boards anticipate facing the same set of hourly marginal fuel costs as is now defined by CEGB. Accordingly, a distribution board's energy classified costs will depend on the marginal energy cost of the national grid, not on the marginal energy cost of that particular board.

The use of extrasystem costs to determine the classification of production costs may become more appropriate with the increase in interconnections between Manitoba Hydro and other utilities. Manitoba Hydro's purchases of nuclear energy at night to conserve water and provide hydraulic head during the day illustrate how external marginal costs can be used to classify costs on the Manitoba Hydro system. During most nights, Manitoba Hydro is able to buy electricity from the United States at such low delivered prices that the electricity is being priced as if it were produced by nuclear generating plants. During the day, Manitoba Hydro often exports power at higher prices that appear to reflect a displacement of coal or oil. For Manitoba Hydro's position of having relatively little generation with appreciable running costs, these market prices can be used to determine hourly energy rates to be used in identifying the energy related portion of generation and transmission costs. An example of such a classification is shown in the following table:

Time Period	Length (Hours)	Market ($/MWH)	MH Load (MW)	MH Energy (GWH)	Energy Cost (000)
Peak	1760	40	2000	3,520	$140,800
Intermediate	3000	25	1500	4,500	112,500
Night	4000	14	1000	4,000	56,000
TOTAL	8760			12,020	$309,300

This method classifies $309 million as energy related costs. All remaining generation and transmission costs would be classified as demand related.

Manitoba Hydro will have to collect significant amounts of data before it can use marginal costs to determine the energy related component of generation and transmission costs. First, the method requires an hourly market price of electricity. Hydro's system operators, who make daily and hourly deals with other utilities, must increase their data retention. Moreover, the system operators must find a deal each hour that sets a price. Second, the method requires extensive class usage data by time period. The hourly prices in the example are applied to hourly system loads. For cost allocation, the hourly prices would have to be applied to hourly class loads. Manitoba Hydro does not have the extensive load research information necessary for implementing a time-of-use allocation method.

CONCLUSIONS

Two cost classification issues confront Manitoba Hydro:

- The appropriateness of classifying generation and transmission costs uniformly
- The appropriateness of using system load factor to classify generation and transmission costs versus direct assignment of specific plant and expenses to demand and energy categories.

Our interviews with Manitoba Hydro system planners indicate that the uniform classification generation and transmission costs is consistent with Hydro's integrated approach to system planning. Hydro plans for and builds transmission facilities to provide transmission capacity required by generating plant additions. Generation capacity expansion plans and costs are evaluated in concert with associated investments in transmission capacity. The integrated nature of generation and transmission planning obviates the practicality of separately classifying these costs.

Hydro's integrated system approach to planning is also consistent with the practice of using load factor to classify generation and transmission costs. Part of this has to do with the uniqueness of a hydro-based system. In contrast to a thermal-based system, which focuses on meeting peak demands, a hydro system must also be planned to meet energy demands given assumed water levels. Hydro's system is planned so that demand and energy requirements are in balance.

The National Association of Regulatory Commissions acknowledges the uniqueness of a hydro system in its "Electric Utility Cost Allocation Manual":

> Certain types of utility production plants are not related to the maximum rate of use (demand-related). For example, hydraulic production may be designed with consideration of maximum storage to produce firm energy requirements over an extended period of time. Therefore, for hydro production, a method is sometimes utilized that classifies part of the hydro plant expenses and related operation and maintenance expenses to energy.

This supports Hydro's planning concept that hydro plants perform dual energy and demand functions.

Unlike a typical thermal system where baseload and peaking plants can be identified and separately classified, the integrated nature of

Hydro's system makes impractical the assignment of specific investments to demand and energy roles. Hydro does not plan or build specific plants to meet specific baseload or peaking needs. Even Hydro's thermal plants, which presumably would fill a peaking role, are sometimes used for baseload or system support purposes. Thus, using load factor to classify generation and transmission costs into demand and energy components is consistent with Hydro's system planning and operations.

As is evident from both utility practice and broad-based regulatory decisions, Hydro's current classification procedures fall within accepted regulatory classification practices.

III. ALLOCATION OF DEMAND RELATED GENERATION AND TRANSMISSION COST

INTRODUCTION

Manitoba Hydro presently allocates demand related generation and transmission costs on the basis of coincident peak demand. This chapter evaluates Manitoba's practice in light of the Board's concern about using coincident peak demand as an allocator where a significant portion of fixed generation and transmission cost has been classified as energy related.

The method adopted for classifying generation and transmission costs will have a significant impact on the methods which can be used to allocate costs to customer classes. Energy classified costs are normally allocated based on annual consumption by class weighted for relative losses to serve typical customers. A scheme that includes classification of costs by time period will generally lead to class allocation based on weighted consumption by time period. Cost classification schemes that classify significant portions of fixed costs as energy related generally do not comport well with class demand allocations that also include a significant energy factor because of the apparent double counting of energy. This chapter presents a series of class allocation methods appropriate for production and transmission demand related costs. Energy related allocation methods are generally straightforward and are not addressed here.

Though cost studies are often presented as definitive, many commission recognize limitations in their precision, as was previously cited in Wisconsin. Some commissions merely use cost studies to test the reasonableness of rates, such as in Pennsylvania:

> Cost-of-service studies submitted by an electric utility were accepted for the limited purpose of testing the reasonableness of its proposed allocation of its revenue requirement among customer classes, despite allegations that the utility's use of the average and excess demand methodology for allocating power supply costs and its use of the modified-zero intercept method for allocating mass distribution costs were not reflective of true cost causation; it was found that the methods employed by the utility were consistent with standards set forth in the Electric Utility Cost Allocation Manual adopted by the National Association of Regulatory Utility Commissioners (NARUC) and with methods approved in prior proceedings and that, in any event, the revenue requirement was not allocated strictly on the basis of the results of the cost of service studies. (Pennsylvania Pub. Utility Commission v. Pennsylvania Power Co., 93 PUR4th 189, 1988).

Most commissions recognize the many ways that have been proposed and accepted for allocating costs, including the Texas Commission:

> In a cost of service study in an electric rate case, the second step, "classification" involves the assignment of the classified amounts the various classes of service by factors related to demand, energy use, and number of customers; a number of different methods exist for allocating costs, such as 1) probability of a negative margin (PONM, or "Probability Peak", 2) the four coincident peak method (4-CP), 3) the four coincident peak average and excess method (4-CP A&E), 4) the four noncoincident peak average and excess method (4-NCP A&E), 5) the near peak method, and 6) capital substitution (CAPSUB). (Re Houston Lighting & P. Co., __ Tex PUC Bull __, Docket Nos. 6765, 6766, Nov. 14, 1986, modified Dec. 4, 1986.)

This range of methods may result in significantly different rate levels for a class of customers.

COINCIDENT PEAK

A utility's maximum demand is important in determining the capacity the utility must have available to it, either as installed capacity or in interchange commitments. Customer consumption coincident with this peak demand determines the utility's maximum demand. This is used as a rationale to allocate demand related costs to customer classes based on each class's contribution to system peak.

The standard coincident demand method is a single CP, using the utility's highest annual demand. Variations include:

- Three/four seasonal peaks - the monthly peak demands during the peak season are averaged
- Summer/Winter demands - the winter peak and the summer peak are averaged, since both can strain the capacity of the system
- Twelve CP - the twelve monthly peaks are averaged. This reflects the constraints placed on the utility's maintenance activities during the Spring and Fall by the peak demands during those months.

The choice of the number of CPs to be used in allocating demand costs is influenced by the relative sizes of the seasonal peaks. The greater the disparity, the more likely the usage of fewer peaks.

The development of coincident peak allocators is demonstrated below, both for a single CP and for summer/winter demands.

Class	Winter Peak	Allocation Factor	Summer Peak	2-Peak Average	Allocation Factor
Residential	500MW	50%	200MW	350MW	38.89%
Commercial	300MW	30%	400MW	350MW	38.89%
Industrial	200MW	20%	200MW	200MW	22.22%
Street Lighting	0MW	0%	0MW	0MW	0.00%
	1000MW	100%	800MW	900MW	100.00%

Each class's contribution to the hourly maximum demand on the system is estimated, then used to develop an allocation factor.

Appendix B contains several citations where a commission has accepted one of the coincident peak methods for allocating generation and transmission demand costs. Several commissions have accepted different methods for different companies. The FERC's acceptances of a single CP in one case and three CP in another case were both upheld on appeal. Kansas has accepted twelve CP and seven CP and has expressed interest in other numbers of months being included in the calculation.

COINCIDENT PEAK AND AVERAGE DEMAND

Average demand is annual consumption divided by the number of hours in the year. This allocation methodology also implicitly classifies part of the fixed production costs as energy related. Mechanically, the average demand is added to the peak demand to determine a composite factor for classification and allocation.

The coincident peak and average allocator is demonstrated below for a single winter peak.

Coincident Peak and Average Allocator

Class	Winter Peak	Annual Energy	Average Demand	Peak & Average	Allocation Factor
Residential	500MW	2,190GWH	250MW	750MW	45.18%
Commercial	300MW	1,577GWH	180MW	480MW	28.92%
Industrial	200MW	1,577GWH	180MW	380MW	22.89%
Street Lighting	--MW	438GWH	50MW	50MW	3.01%
	1000MW	5,782GWH	660MW	1660MW	100.00%

This method sums average demand and peak demand, resulting in an implicit energy classification of less than the utility's load factor. An alternative method scales the peak demand down to the complement of the system load factor, resulting in an energy classification equal to the utility's load factor.

Coincident Peak and Average Allocator
(System Load Factor Method)

Class	Annual Energy	Average Demand	Winter Peak	Scaled Peak	Peak & Average	Allocation Factor
Residential	2,190GWH	250MW	500MW	170MW	420MW	42.00%
Commercial	1,577GWH	180MW	300MW	102MW	282MW	28.20%
Industrial	1,577GWH	180MW	200MW	68MW	248MW	24.80%
Street Lighting	438GWH	50MW	0MW	0MW	50MW	.50%
	5,782GWH	660MW	1000MW	340MW	1000MW	100.00%

Various commissions have accepted the coincident peak and average demand allocation method. A list of citations is presented in Appendix C. The commissions have used several definitions for the coincident peak demand. North Carolina has used a summer/winter peak in several cases. North Dakota used twelve CP in its method. Texas has differentiated between production and transmission, using peak and average demand for transmission and a statistical method for production.

AVERAGE AND EXCESS DEMAND (AED)

AED is one of the most popular composite methods for classification and allocation. Average demand is annual consumption divided by the number of hours in the year. Excess demand is the difference between annual peak and average demand. Effectively, AED classifies a portion of the fixed production and transmission cost as energy related, the portion being determined by the utility's load factor. In this respect, Manitoba Hydro's classification scheme follows the norm for AED.

The excess demand, the portion in excess of average demand, is allocated on class peak demand in excess of average demand. Class peak demand is normally considered to be class noncoincident peak, i.e, the maximum load the class ever places on a utility.

The development of the average and excess demand allocation factor is demonstrated below.

Average and Excess Demand

Class	Winter-Peak	Annual Energy	Average Demand	Non-Coincident Peak	Excess NCP	Scaled Excess	AED	Allocation Factor
Residential	500MW	2,190GWH	250MW	625MW	375MW	196MW	446MW	44.62%
Commercial	300MW	1,577GWH	180MW	375MW	195MW	102MW	282MW	28.20%
Industrial	200MW	1,577GWH	180MW	210MW	30MW	16MW	196MW	19.57%
Street Lighting	0MW	438GWH	50MW	100MW	50MW	26MW	76MW	7.61%
	1000MW	5,782GWH	660MW	1310MW	650MW	340MW	100MW	100.00%

A list of citations adopting AED is presented in Appendix D. The citations indicate that some commissions use variations of the AED. The Texas commission used a four CP AED for transmission costs, preferring a statistical approach for production.

The calculation of excess demand for allocating the excess portion of fixed production costs results in flat loads, such as signal lights and some basic metals, being charged the same as single CP. AED sometimes use more than a single peak demand, i.e., using the four summer months or the 12 monthly CPs for determining the excess.

Proper application of the AED method would address the Board's concern about using coincident peak demand to allocate costs classified using system load factor. Allocating excess demand on the basis of class noncoincident peak minus average demand eliminates any double counting of average demand in the peak allocator.

AED is sometimes used with a method that classifies hydro production costs to demand and energy components on the basis of available energy from the Hydro plants under average and low water flow conditions. First, a percentage relationship is developed from the amount of increased energy available under average water conditions compared to energy available under low water conditions. This percentage is then applied to the hydro expense items to determine the energy related portion. The remaining hydro plant expenses are classified as demand related.

RECOGNITION OF SPECIAL LOADS

Many utilities have a customer or group of customers whose service requirements are unusual in comparison to the normal customer. These unusual service requirements can include restricted times of consumption, interruptibility, or geographic location. Some commissions have recognized these unusual service requirements in determining how to apply the allocation process to that class. Various citations are included in Appendix E.

The U.S. Federal Energy Regulatory Commission ordered the exclusion of interruptible loads in determining a twelve CP allocation factor. The Indiana commission excluded 75% of the interruptible load in determining a twelve CP allocation factor. The Colorado commission, using AED, specified that no excess demand would be attributable to interruptible and curtailable customers. A similar argument would also be applicable to street lighting loads, when system peak demand is normally during daylight hours.

For off-system loads, the Idaho commission dedicated losses associated with sales and wheeling to those customers, refusing to allow normal customers to see their costs affected by this special transaction.

Statistical Approaches

Some utilities use statistical techniques for allocating demand costs. A collection of regulatory citations is presented in Appendix F. The basis for these statistical techniques is the system planning methods used in determining the capacity needed to serve customers reliably. The most common system planning criteria is Loss of Load Probability (LOLP). LOLP identifies a probability for each hour of the year that the utility will be unable to meet all load on the system. LOLP is dependent on hourly load, units planned to be in service, and their expected outage rates. The California Public Utility Commission is a major proponent of using LOLP for allocating production demand costs in conjunction with a marginal energy cost analysis. Houston Lighting & Power uses a variation of LOLP, the Probability of Negative Margin (PONM).

Both PONM and LOLP develop a probability or statistic for each hour of the year. This statistic is then used to assign costs to each hour and then to each class load during the hour. Two methods are used to develop the assignments to each hour. The statistic can be treated as a unit price, with each kWh during the period being charged that price. Alternatively, the statistics can be treated as a total cost, with the statistic allocated among the kwh during the period. The charges to hours are shown below for the two methods.

Statistical Allocation Example

				Statistic As Cost		Statistic As Price	
Load Definition	Average Load	Duration	Statistic	Weighted Duration	Factor	Weighted Energy	Factors
High Load	1000MW	100 Hours	.1	10.000	32.609%	10.000	36.765

Medium Load	840MW	2000 Hours	.01	20.000	65.219%	16.800	61.765
Base Load	601MW	6660 Hours	.0001	.666	2.172%	.400	1.470
		8760 Hours		30.666	100.000%	27.200	100.000

The allocation to class is shown in Appendix G.

Many commissions have accepted a statistical method for allocating demand costs. The Colorado commission recognized some problems with a statistical process. First, statistical methods are data intensive, requiring class load data for all 8,760 hours in the year. Many utilities do not have load research data sufficient to provide these estimated loads. In our review of Manitoba Hydro's records, we have not found sufficient data for implementation of one of thesestatistical cost allocation methods. A second problem is the proprietary nature of the software used to allocate costs. This proprietary nature, and the cumbersomeness of the data, will often limit the ability of commission staff and intervenors to analyze the data and procedures for easonableness. The Colorado commission thus rejected a statistical method proposed for application in the case at hand but ordered the utility to continue investigating the rejected method.

CONCLUSIONS

Based upon this review, Hydro's classification and allocation procedures fall within the framework of accepted regulatory positions. Under Hydros's method, a lower percentage of overall generation and transmission costs is classified to energy than would result under a peak and average method on a traditional thermal system. Consequently, Hydro recognizes both the fuel substitution argument as well as a balanced position on the variable component of fixed cost.

IV. CLASSIFICATION OF DISTRIBUTION COSTS

INTRODUCTION

Manitoba Hydro classifies distribution costs as follows:

- Meters and services are customer related
- Line transformers are demand related
- Distribution poles, wire and related items are 60% demand related and 40% customer related.

This chapter reviews some of the traditional means for classifying distribution costs, such as the Minimum System and Zero Intercept Methods, and assesses the appropriateness of each method given the data available to Hydro.

DEFINITIONS OF DISTRIBUTION COSTS

A utility's distribution system includes all land, plant and equipment necessary to get electricity from the bulk power supply system to the customer's equipment. The distinction between distribution and transmission varies among utilities. In the United States, the Federal Energy Regulatory Commission Uniform System of Accounts for Electric utilities contains the following electric plant instruction:

> "Distribution system" means all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includable in the transmission system, as defined

in paragraph A, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system.

Note: Stations which change electricity from transmission to distribution voltage shall be classified as distribution stations.

The bright line between transmission plant and distribution plant, if such a bright line exists, is at the input to "stations which change electricity from transmission to distribution voltage." When a utility has multiple voltage levels from which customers receive service, questions arise as to the appropriate station to be considered a distribution station.

In discussing the options Manitoba Hydro has in classifying distribution plant, we shall assume that the corporation has established a definition for the distinction between transmission and distribution. We understand that Hydro defines distribution plant costs as those costs which are incurred to distribute electricity at voltages below 30 KV. Based on the above bright line, we will discuss how costs are incurred on the distribution system, how that cost incurrence leads to potential competing classifications of cost, and the implication on the definition of a customer for allocating cost to street lighting. The regulatory acceptance of these competing classification methods is documented in Appendix H.

A distribution system consists of stations, poles and wires, transformers, and services. The primary cost of a distribution system is for depreciation, return, and taxes, i.e., costs driven by the utility's investment in the distribution plant. The operating expense of the distribution system is generally incurred to protect and to maintain the investment. Under this system of costs, distribution costs are fixed, invariant with the energy that may be expected to flow across the distribution system. The system designer is the primary controller of the annual cost of the system, either in specifying the investment and carrying cost or in staffing the preventive maintenance and operating crews. The annual cost depends on the number of customers expected to be served and the demand expected to be met.

Variable distribution costs, such as line and transformer losses, are generally not recognized by most accounting systems, but rather remain charged to system supply. A separate accounting for electrical losses has generally not been necessary. However, the increased emphasis in recent years on wheeling electricity may lead to a formal accounting of line losses as distribution expenses. Gas transmission utilities now record fuel used in compressor stations as transmission expense instead of a production expense. Electric utilities could analogously record transformer losses as a distribution expense. One step further would be to include the recognition of line losses as a distribution expense.

STATIONS

Class cost of service studies almost universally treat the cost of stations as demand related. However, a portion of the cost of stations can be classified as customer related.

The investment in a transmission station is almost directly proportional to the anticipated demand the station is designed to serve. Accordingly, station costs are classically treated as demand related.

In theory, stations have some economies of scale. These economies derive from the costs which would be incurred independently of the size of the station. These fixed costs include land acquisition, drafting, and transmission access, among other costs. Since these costs do not vary with demand, it is inappropriate to classify them as demand.

These fixed costs could be considered to be minimum station costs and have been recognized as such in rate making by some generation and transmission cooperatives. For instance, at least one G&T Coop has set up customer classes based on the size of the station transformer. The coop sets a monthly charge based on the standard cost of each size of station. This utility, in practice, effectively treats the cost of stations entirely as customer related.

POLES AND WIRES (ALSO UNDERGROUND CONDUIT AND CONDUCTORS)

Class cost of service studies generally recognize that poles and wires have both customer and demand related costs. This was recognized in Pennsylvania:

> While strictly speaking, overhead lines are sized to serve peak demand, a utility's investment in distribution facilities is a result of both size and length and generally the greater the length the greater the number of customers.

Manitoba Hydro acknowledges this concept in its classification of pole, wire, and related items as 60% demand related and 40% customer related.

Many methods have been established to classify poles and wires, the most simple being a fixed percentage, as practiced by Manitoba Hydro. This practice has regulatory support, such as in Pennsylvania:

> A utility's classification of its investment in overhead lines as 60 per cent demand related and 40 per cent customer related was within the zone of reasonableness, based on the commission's experience with other utilities.

In this instance, the subject utility adopted the same ratio that is used by Manitoba Hydro. Our experience with fixed proportions being classified as demand ranges to a high of 100% and a low of 30%. We note that our staff was told by Manitoba Hydro employees that the distribution system is sometimes "designed to serve new customers whether the demand is low or high." This design criterion could justify classifying the cost of lines entirely as customer related. However, the same session resulted in notes identifying the general criteria of voltage drop and expected loads on the system over a 20 year period.

The basis for a two part classification of poles and wires depends upon the way utilities serve their customers. When groups of new customers are added, the utility installs poles and wires sufficient to meet the needs of the customer. The cost of the line extension increases with the number of customers, generally because the length of wire is proportional to the number of customers served. The size of customer is also important. Greater electric loads will require larger lines that must be supported by heavier poles. The fixed percentage classification method provides one method to recognize these two facets of the cost of poles and wires.

Other commonly accepted methods for classifying poles and wires include the Minimum System and Zero Intercept Method. The Minimum System identifies the types of poles and wires a utility uses to provide minimal service to a small customer, then reprices the distribution system as if each pole were replaced by the lightest, cheapest pole commonly in inventory and as if each length of wire were replaced by the lightest, cheapest wire commonly in inventory. The cost of this Minimum System is then deemed to be customer related. The remaining costs are considered to be demand related.

Conceptually, the Minimum system is similar to the classification scheme discussed previously wherein a G&T Coop set up customer classes based on the size of the station serving the customer. The smallest class of stations would be equivalent to the Minimum System.

The basic concepts of the Minimum System and the Zero Intercept Method are presented in the following table, which postulates three standard distribution configurations:

Distribution Line Classification Example

Configuration	Unit Cost ($/KM)	Load Capability (KW)	Lines Installed (KW)	Installation Cost ($000)
Low Load	18,000	5,000	10,000	$180,000
Medium	20,000	6,000	100	2,000
High Density	22,000	7,000	100	2,200
			10,200	$184,200

The predominant configuration is for low density load. This represents the minimum sized system which the utility installs. Pricing the entire system at the unit cost of this configuration results in a Minimum System cost of $183.6 million (10,200 KM @ $18,000/KM). Since the Minimum Systems costs 99.7% of the cost of the installed system, 99.7% of the cost of distribution lines would be classified as customer related, with only 0.3% classified as demand related. This extreme classification is consistent with our interviews with Manitoba Hydro employees. We expect that actual data would produce less extreme results.

The unit costs can be extrapolated to zero load carrying capability. The example data in the table infers a cost of $8,000/KM plus $2/KW. The zero Intercept Method results in a customer cost of $81.6 million (10,200 KM @ $8,000). Since the Zero Intercept Method customer costs are 44.3% of the cost of the installed system, 44.3% of the cost of distribution lines would be classified as customer related and 55.7% as demand related.

The Distribution Line Classification Example presented in the above table is greatly simplified. Typically, the investment must be normalized to eliminate any distortions caused by the varying cost escalations that could affect the installed cost of each size of conductor or pole. Even when a utility has maintained pole and wire records by year of installation and size of equipment, the analysis is extensive. We found no indication that Manitoba Hydro maintains such records. Accordingly, significant efforts would be necessary to estimate the appropriate percentages of distribution line costs that should be classified as customer related and demand related under either the Zero Intercept or the Minimum System methods.

Maine has adopted the concept of minimum system but rejected the use of the cost of the minimum system in setting a customer charge. Maryland adopted the minimum system concept, but went one step further in using only excess demand (relative to that which could be served by the minimum system) in allocating demand costs. New York followed Maryland on the minimum system concept but rejected the concept of an offset to class demands for allocating the demand component. The Utah Commission rejected the minimum system, suggesting that each component of cost be strictly classified as demand or customer.

The Zero Intercept Method can be applied in two ways. The most common approach identifies the cost of a system with wires of zero diameter and poles of zero height. The unit cost of these hypothetical wires and poles are based on the installed cost of wires and poles of various sizes, from which trend lines are established. The trend lines reveal the unit cost of hypothetical zero diameter lines and zero height poles. These unit costs are then used to cost a hypothetical zero intercept system. Alternatively, the cost of lines of differing load carrying capacity could be used to create a trend line of cost versus capacity. The trend line could be used to estimate the unit cost of zero capacity, the unit cost to be used in evaluating the hypothetical system. The Zero Intercept Method contains some of the features discussed above for stations, especially the cost of land acquisition, drafting, et al.

The customer component can also be treated as distance-related. As stated in the Pennsylvania decision, one justification for a customer component of poles and wires is that "generally, the greater the length, the greater the number of customers". One way to interpret this is that customer related costs are a surrogate for distance related costs. A utility incurs less costs for customers closer to a distribution station than for customers far from a distribution station. Natural gas pipelines often reflect this cost pattern in having transportation rates stated in Mcf-miles. Thus, not only is the quantity important, but also the distance the gas travels.

A distance sensitive classification was an issue in the appeal of a South Dakota commission order in an electric case. Rather than the traditional demand and customer classifications, a mileage classification was used in place of the customer classification. The commission gave a stronger weight to the demand component despite some evidence supporting a significantly greater mileage classification.

Under the general concept of equity, most people advocate postage stamp rates, i.e., the same charge for all customers in an area. Thus, there are no price breaks for each kilometer a customer is closer to the station than is his neighbor. However, the equity argument is minor compared to the issue of administrative feasibility. A rate that varied with the distance from the station would have customers involved with selecting the location of new stations that could lower their unit price or the routing of lines. Further, when networks are switched from one station to another, rates would have to change accordingly.

One concept that may overcome the administrative rationale for tying length to the number of customers is wheeling. Though wheeling primarily occurs on the transmission system, generators may wish to use Manitoba Hydro's distribution system. At that time, Manitoba Hydro may wish to use distance in place of customer cost. The concept has not yet been developed sufficiently to discuss in any greater depth.

LINE TRANSFORMERS

The traditional classification for line transformers is 100% demand related. There is some justification for treating line transformers as having a small customer component. A zero intercept method would be used to identify the customer related component and demand related component. Though there is theoretical support for the two classifications, we are unfamiliar with it being proposed or adopted by any regulatory commission.

METERS AND SERVICES

Cost allocation procedures have typically treated meters and services as customer related. There is a higher cost associated with sophisticated industrial metering equipment. This higher cost can be handled by classifying some services and metering costs as demand related. Some marginal cost proponents have advocated this unorthodox approach. Most analysts treat the varying cost of services and meters by using a weighted count of customers in the allocation process.

CONCLUSIONS

Hydro's present plant records are not subdivided to support studies such as Minimum System or Zero Intercept. Additional analyses of work orders, purchase orders and design criteria may lead to representative solutions for the use of these methods. At this time, it is doubtful that appropriate distributions can be made between primary and secondary facilities. Based on our experience with other utilities and the existing 60/40 demand, customer separation of pole and wire is within acceptable limits on an overall basis. The generally accepted demand allocation procedure is followed for substation facilities. Regarding meters and services, the allocation on a weighted customer basis follows industry standards.

V. *CUSTOMER WEIGHTING FOR STREET LIGHTING*

INTRODUCTION

Manitoba Hydro allocates customer related distribution plant to customer classes on the basis of unweighted and weighted customer count. However, Manitoba Hydro's most recent cost of service study does not assign the street lighting class any customer related distribution plant costs. This chapter provides guidance on procedures to define and weight a "customer" in this class, given the data available to Hydro.

NEED FOR WEIGHTING

After the customer related portion of a cost component has been identified, customer related costs are allocated to customer classes based on the number of customers in each class. However, the number of customers in each class must be weighted to reflect the appropriate cost causation aspects of the class.

The clearest example of the need to weight the number of customers in each class is the allocation of meters. Large customers required sophisticated meters including current transformers, potential transformers, reactive meters, etc. These meters are much more expensive than the simple meters used for residential customers. The allocation of the customer component of meters (generally the only component of meters) involves weighting the "by class" customer count by the relative prices of meter as shown in the example below:

Weighted Meter Allocation Example

Customer Class	Meter Cost	Weight	Customers Count	Weighted Customers	Allocation Factor
Residential	$100	1	100,000	100,000	62.50%
Commercial	500	5	10,000	50,000	31.25%
Industrial	10,000	100	100	10,000	6.25%
Street Lights	0	0	500	0	0.00%
TOTAL			110,600	160,000	100.00%

In the example, a weight of "0" is applied to the street light customer count on the assumption that street lights are not metered. This assumption is generally appropriate. Exceptions include: (1) some systems that meter strings of street lights and (2) a pro rata share of test meters that determine the actual wattage of street lights and the length of time they operate.

Determining customer weights for services follows the same general method used for meters. The differences relate to determining the average service cost for each class. Further, accounting practices may differ among utilities for the investment necessary to connect street lights to the distribution system.

- When the connection is capitalized as part of service, the average cost of services for street lights is non-zero. Accordingly, a non-zero weight can be used for determining the weighted customer count of street lighting for the purposes of allocating services.

- When the cost of the connection is capitalized as part of the street lighting investment account, the cost of services for street lights is zero. In such situations, it is appropriate to use a zero weight for the street lighting customer count when allocating services.

The customer weight for street lighting should depend on how costs are incurred. Utilities incur the cost of the customer component of lines as a result of the length of the distribution facilities. The length of such facilities is generally proportional to the number of customers. Street lighting design can change the length of the distribution facilities. The customer weight for street lighting should reflect this influence, if any.

The use of either marginal or embedded costing approach will affect whether or not street lighting is assigned any customer cost responsibility. Using a marginal approach, the New York Commission found that street lighting was incremental to an electric company's distribution system and should be exempted from customer cost responsibility. The incremental customer concept has also been advocated by the California Commission in general, though not specifically with regard to street lighting. However, in a 1987 Southern California Edison case, the California Commission ruled that it was unnecessary to include a minimum distribution system charge in street light customers based on the transformer, meter, service drop approach. It is important to note that these rulings concern marginal or incremental costing approaches. Under an embedded cost approach (such as that used by Hydro), the street lighting class should bear some portion of customer related costs.

Street lights can result in a higher design cost for poles and wires. Many utilities install poles and wires along the back property line, finding that such easements are easier to obtain and that the lines are cheaper to install. Street lights normally are on the front property lines, either requiring a separate set of poles and wires or possibly a more expensive routing of the common poles and wires. When a utility in the United States installs a separate set of poles and wires, the installed cost of such facilities is directly assignable to the cost of street lighting. However, if a utility incurs additional costs to route its distribution system to meet the needs of street lights, utilities do not necessarily account for these additional costs separately. Thus, the design of the distribution system can cause a nonzero customer cost for street lights.

The Maryland Commission emphasized the importance of looking at specific circumstances where local requirements cause increased costs to be incurred, requiring that the increased costs be collected directly from the relevant customers. This would support a non-zero customer weight for street lighting when street lighting increases the cost of the network.

APPLICATION TO MANITOBA HYDRO

Customer related costs are those which vary with the number of customers. In theory, customer costs reflect the benefit of service availability through connection to the electric utility system. According to embedded cost principles, the street light class shares the benefit of service availability and, therefore, should be allocated some portion of customer costs. This would support allocating the customer portion of the primary distribution system to the street light class, assuming that Hydro capitalizes the secondary distribution system to the street light account.

Some street lights on Manitoba Hydro's system are mounted on "exclusive" poles, while others are mounted on "shared" distribution poles. Our analysis indicates that about on-third of Hydro's street lights are mounted on shared distribution poles. Mounting street lights on distribution poles could increase the height of the pole to provide required clearance above the distribution lines. This would support classifying some portion of shared distribution poles (e.g., the top five feet) and associated wire as a customer related cost allocable to the street light class. However, Hydro does not use a higher distribution pole to accommodate street lights. Instead, Hydro utilizes the space between the primary and secondary lines normally used to accommodate a transformer.

In our experience, distribution investment typically can be subfunctionalized between primary and secondary, with approximately 70% of the investment being attributable to the primary distribution voltage and 30% of the investment being attributable to the secondary distribution voltage. Investment in the primary distribution system is heavily influenced by the demand the system must serve. On that basis, 70% of the investment in the primary distribution system is typically classified as demand related, and 30% as customer related. On the secondary distribution system, the customer role more nearly balances the demand role of investment. Accordingly, it is appropriate to classify the secondary distribution system as 50% demand related and 50% customer related.

It is appropriate to allocate some portion of both demand and customer-related primary distribution system costs to streetlighting. However, since Hydro cannot distinguish street lights with their own secondary system from those which connect directly to Hydro's secondary system, it may be appropriate to allocate a full portion of secondary system demand-related costs, but not secondary system customer costs to the streetlighting class.

Customer cost allocable to the street lighting class should be allocated on the basis of weighted customer count. This would be done by counting the number of connections that street lights make to the distribution system to develop the customer count. The number of connections, or the count, would be used to allocate customer cost. The number of street lights per connection, or relay, on Hydro's system depends on the size and type of street light. For lights less than 400 w, the average is approximately 10 lights per relay. Other sizes of lights average 6 lights per relay. However, not all street lights are connected through relays. We understand that more recently installed street lights are directly connected and controlled by light sensitive cells because such installations are less expensive and simultaneous energization of streetlights is not necessary in residential areas. Further, some street lights, typically high wattage lamps at roadway interchanges, have their own distribution system. While in theory, each directly connected street light would be counted as a customer, Hydro should investigate the number of such installations to determine the appropriate customer weight.

CONCLUSION

Using the above range, every six large lamps or ten small lamps would be counted as one customer for allocation purposes. The customer count for street lighting should be the weighted average number of street lights per connection. We understand that Hydro has the data necessary to develop a weighted customer count for street lighting. We recommend that Hydro develop a weighted customer count for street lighting to allocate customer costs to this class using the available data on the number of street lights by size, type and size of relay. Having developed a weighted customer count for street lights, Hydro can use it to allocate the customer component of the primary distribution system. We believe that this is a reasonable method for allocating customer costs to the streetlighting class, given the availability of Hydro's data. Such an approach would be within the range of methods used by other electric utilities.

APPENDIX A
REGULATORY CITATIONS ON
CLASSIFICATION OF GENERATION AND TRANSMISSION

[COLO.] Nonfuel production operations and maintenance expense for an electric utility was allocated on an energy basis, despite the fact that a portion of the expense was demand related, because cost allocation methods were undergoing intensive review and a change in methods before the review was complete could result in the underminging of the stated goal of rate continuity. Re Public Service Co. of Colorado (1985) 68 PUR4th 363.

[D.C.] In determining the correct allocation of transmission plant, the commission accepted the company's plan that classified transmission plant costs as 50 percent demand related and 50 percent commodity related and then allocated the capacity component on the basis of a single daily peak-load measure. Re Washington Gas Light Co. (1983) 4 DC PSC 1, 52 PUR4th 1.

[FLA.] Where the conversion of a plant from oil fired to coal fired was purely for energy savings and the original plant investment continued to be allocated on the basis of demand, and where the construction of another unit was certified for the dual purpose of meeting increased demand and lowering system fuel costs, the commission found that classification of all of the construction work in progress for the conversion and a portion of the CWIP for the new unit as energy rather than demand related was appropriate. Re Tampa Electric Co. [1982] 49 PUR4th 547.

[IDAHO] For jurisdictional allocation purposes, and electric utility's energy-only congeneration and small power production payment were split between energy and capacity' the commission found that there were implicit capacity payments within the energy payments. Re Idaho Power Co., 76 PUR4th 326 (1986).

[N.C.] The commission was again persuaded that the cost allocation method to be utilized in the present proceeding should recognize the energy-related portion of fixed costs, since it reasoned that not all fixed costs represented the cost of meeting system peak demand, and that a significant portion of fixed costs represented the cost of producing kilowatt-hours during many hours of the year and of producing such kilowatt-hours at a lower fuel cost per kilowatt-hour. Re Carolina Power & Light Co. (1983) 55 PUR4th 582.

[MD.] The commission held that demand-related assignments of surcharge costs relating to participation in a pumped-storage electric generating project were reasonable and should be accepted. Re Potomac Edison Co., 76 Md PSC 707, Case No. 7878, Order No. 67254, Dec. 30, 1985.

[MICH.] The commission affirmed a cost-of-service allocation methodology that designated production and transmission plant at 75% demand related and 25% energy related, finding that allocating above average fixed costs to high-load factor customers when apportioning average energy costs was equitable and would result in each customer class contributing more toward its own cost of service. Re Detroit Edison Co. (1985) 68 PUR4th 241.

[MO.] Where a new nuclear plant being phased into rates is a base-load plant that will be used year round, the costs of that plant should be shared by customer based on year-round usage, not just peak usage. Re Union Electric Co. (1985) 27 Mo PSC NS 183, 66 PUR4th 202.

[PA.] The commission accepted the utility's classification of 45 per cent of the capital costs associated with a nuclear plant as energy related. Pennsylvania Pub. Utility Commission v Metropolitan Edison Co. (1983) 56 PUR4th 230.

[PA.] Three Mile Island Unit 1 nuclear plant-related costs were allocated based on a 55% demand and a 45% energy allocation, rather than a 100% demand basis, to reflect the benefits of operating the generating unit. Pennsylvania Pub. Utility Commission v. Metropolitan Edison Co., 60 Pa PUC 349, R-842770 et al., Oct. 24, 1985.

[PA.] The commission accepted an electric company's classification of a portion of the capital costs related to a nuclear unit as energy related, noting that large energy users, as a class, are the prime beneficiaries of the lower energy costs associated with nuclear generation and it is therefore appropriate that they bear a major responsibility for the capital costs. Pennsylvania Pub. Utility Commission v Pennsylvania Electric Co. R-822250 et al. Oct., 14, 1983.

[VT.) The board accepted a "fuel offset method: of allocating capacity costs, whereby capacity costs in excess of the cost of peaker units would be allocated on the basis of the difference between marginal and average costs' a portion of embedded capacity costs would be allocated on the basis of energy consumption, rather than coincident peak; the practical effect of the method was that customer classes with high off-peak usage and relatively low contribution to system peak would pay higher amount of capacity costs. Re Central Vermont Pub. Service Corp. (1985) 65 PUR4th 441.

[WASH.] An electric utility was directed to calculate the cost of service by classifying production plant between energy and demand costs on the basis of a peak credit method and multiple peaks. Washington Utilities & Transp. Commission v Washington Water Power Co. Cause Nos. U-82-10, U-82-11, Dec. 29, 1982.

[WIS.] Under the "base-intermediate peak" method for allocating costs of electric generating plant, all base load is allocated on the basis of energy consumption, intermediate load plant is allocated on the basis of twelve monthly peaks, and peaking plant is allocated on the basis of the single system peak demand. Re Wisconsin Electric Power Co. 6630-ER-16, Dec. 21, 1982.

[WYO.] In light of the low cost of energy for the electric company's peaking units, a "peak credit method" was adopted whereby energy allocation was spread in an equal percentage to each customer class, thus causing industrial customers to bear a greater burden of plant costs. Re Pacific Power & Light Co. (1983) 54 PUR4th 129.

[UTAH] The commission found that, since an electric company's mining operation was not sized to meet the peak operating mode of the company's generating units but rather was sized to provide a year-round coal supply, the equation of fixed costs and demand costs by which the company sought to classify its captive coal property costs as demand related, because they were fixed rather than variable as they did not vary with the volume of coal produced, broke down, and that the company should continue to classify these coal property costs as energy related. Re Utah Power & Light Co. (1983) 52 PUR4th 436.

APPENDIX B
REGULATORY CITATIONS ON USING COINCIDENT PEAK DEMAND ALLOCATION FACTORS

[ARIZ.] An electric utility's use of a four-month coincident peak demand methodology for allocation costs to production and transmission, various classes of service, and various jurisdictions was accepted; no party attacked the jurisdictional cost allocation and the commission noted that it might be bound by the Federal Energy Regulatory Commission's adoption of the 4-CP methodology. Re Arizona Pub. Service Co., 77 PUR4th 542 (1986).

[ARK.] In setting wholesale electric rates charged by a rural electric cooperative association to its member retail cooperatives, a four-moth summer coincident peak method was adopted to allocate demand costs (fixed production costs were classified as demand related); the commission rejected a cost allocation method proposed by the commission staff described as the "average and peak reserve method," whereby the percentage of fixed costs classified as demand related was equal to system average demand divided by system peak (the result being the system load factor, multiplied by the sum of one plus the percentage reserve margin). Re Arkansas Electric Co-op Corp. (1985) 65 PUR4th 269.

[FLA.] The additional revenue requirement associated with nuclear plant decommissioning costs was allocated between classes on the basis of production demand. Re Decommissioning Costs of Nuclear Powered Generators (1983) 55 PUR4th 1.

[U.S.C.(D.C.)] The commission's decision to accept a single peak (1-CP) method of allocating demand costs among classes of customers, as opposed to a 12 monthly coincident peak average (12-CP), was not arbitrary and capricious. Cities of Batavia et al. v. Federal Energy Regulatory Commission (1982) 217 US App DC 211, 672 F2d 64.

[U.S.C.A.(D.C.)] A federal Energy Regulatory Commission decision that found the proposed use of a three-month coincident peak method of demand cost allocation by an electric utility for wholesale rates was unreasonable was affirmed where the system did not have a summer peak demand significantly higher than the winter demand and where the system had a high level of use throughout the year. City of Bethany v. Federal Energy Regulatory Commission (1984) 234 US App DC 32, 727 1131.

[IDAHO] Considering the reasonable methods for allocating demand for a mixed hydrothermal system and the interests of interjurisdictional harmony, the commission adopted a 12 coincident peak demand allocator. Re Washington Water Power Co. (1985) 65 PUR4th 100.

[IDAHO] The "coincident peak" method (CP) of demand cost allocation measures the demands of the various service classes at the time of the system or subsystem peak; the CP methods assumes that he cost associated with the maximum load should be divided among the customers causing such peak load, regardless of the magnitude of their demands at any other time. Re Intermountain Gas Co., Case Nos. U-1034-137, U-1034-139, Order No. 20966, Dec. 31, 1986.

[ILL.] A four-coincident peak method of allocating power pool facilities and fixed expenses was adopted where an electric utility's peak demand was during the four summer months. Re Union Electric Co. (1983) 53 PUR4th 565.

[IOWA] A method using 12 monthly coincident peaks was used for allocating demand costs. Re Union Electric Co., 72 PUR4th 444 (19860.

[KAN.] A 12-month coincident peak method has been used traditionally for jurisdictional allocation of electric projection plant. Re Wolf Creek Nuclear Generating Facility. (1985) 70 PURth 475.

[KAN.] While a utility's traditional rate design using a seven-month system peak method for allocating demand costs was accepted, the state corporation commission expressed interest in other methods utilizing one, three, four, or twelve month coincident peaks. Re Kansas Ga & E. Co. docket No. 128, 139-U, Dec. 31, 1981.

[KAN.] A 12 month coincident peak demands costs allocation factor was found appropriate as it recognizes investment in base-load facilities which are utilized all year. Re Wolf Creek Nuclear Generating Facility, Docket Nos. 120,924-U, 142,099-U, Sept. 27, 1985.

[KAN.] A 12-month coincident peak method was used for jurisdictional allocation of electric production plant. Re Kansas City Power & Light Co., 84 PUR4th (1987).

[KY.] The commission rejected a cost-of-service study based on the coincident peak methodology because that methodology would violate the principle of cost causation by allocating additional generation costs, caused by duration of load and not system peak, to a class that could have been served at a lower cost by peaking units, and accepted a study based on embedded production costs because that study, having been based on consideration of many factors and not solely system coincident peak demand, better reflected the principle of cost causation. Re Kentucky Utilities Co. (1983) 52 PUR4th 408.

[MD.] It was proper for a natural gas distributor to allocate the costs of its storage gas used for service in the winter season on the basis of annual weather sensitive demand and to allocate purchased gas costs on the basis of peak design day demand, exclusive of interruptible demand, where both factors involved weather sensitive load unrelated to base load volumes already reflected in winter load calculations. Re Washington Gas Light Co., 77 Md PSC 30, Case No. 7649, Order No. 67286, Feb. 10, 1986.

[MASS.] The allocation of the costs related to a gas company's propane production over the winter months was a more accurate reflection of cost causation than allocating them on the basis of design day responsibility or twelve months' energy use because the company's propane plant was continually used on a relatively consistent basis to service firm customers in the winter months. Re Haverhill Gas Co. (1982) 49 PUR4th 426.

[MINN.] The summer-winter peak method for determination of the demand allocation factor was used instead of the 12 coincident peak method, because the former method would allow for consistency among the three jurisdictions in which electric utility operated. Re Northern States Power Co., 75 PUR4th 538 (1986).

[MO.] An electric utility's production and transmission demand costs were allocated using a 4-CP methodology, even though the commission had, in the past, rejected the theory that new capacity is added solely to meet system peak and had accepted the time-of-use =method and its underlying theory of cost causation; the commission had only tow allocation proposals before it and both were based on peak responsibility methods. Re Kansas City Power & Light Co., 75 PUR4th 1 (1986).

[MO.] The 4-CP methodology was used to determine a electric company's system production and transmission demand and allocators; the commission favored the 4-CP method over the 1-CP method because the use of multiple peaks recognizes that plant is used at times other than the single system peak. Re Kansas City Power & Light Co., 75 PUR4th 1 (1986).

[MO.] In allocating production-related demand costs among jurisdictional electric customers, the commission affirmed its policy of allocating costs to customer classes based upon time-of-use methodologies and asserted that it would be proper for jurisdictional allocations to mirror customer classes based upon time-of-use methodologies and asserted that it would be proper for jurisdictional customers of an electric utility comprise only 5% of its business, yet have a higher load factor than other customers, it is appropriate to base jurisdictional allocations on the single coincident peak method rather than average and peak method. Re Arkansas Power & Light Co., 74 PUR4th 36 (1986).

[N.J.] The board found a peak-day methodology was more appropriate than an average and excess methodology for a gas company's cost-of-service study. Re South Jersey Gas Co. (1985) 65 PUR4th 452.

[N.M.(P.S.C.)] While not disturbing an electric utility's inventory calculations and allocation factors using the single coincident peak method in the case before it, the commission held that the 12-month coincident peak method of allocation would be more appropriate for a jurisdictional allocation. Re Public Service Co. of New Mexico, 73 PUR4th 617 (1985).

[N.C.] The summer coincident peak method was held to be the most appropriate method for making jurisdictional allocations of expenses between customer classes. Re Duke Power Co. (1982) 49 PUR4th 483.

[N.C.] The summer coincident peak method is the most appropriate method for allocating electric demand costs. Re Duke Power Co. (1985) 69 PUR4th 375.

[OHIO] The commission adopted, for the purpose of jurisdictional allocations, an electric company's average of 12 monthly peaks method that was premised on the assumption that the capacity, requirement of the system was determined by those 12 peak loads, and therefore, demand-related costs should be apportioned in accordance with each customer's coincident demand at the time of those 12 peaks. Re Ohio Edison Co. (1983) 55 PUR4th 423.

[PA.] The commission approved an electric company's bulk power supply cost allocation, which allocated production and transmission demand-related costs on the noncoincident peak method, considering two summer and two winter months. Pennsylvania Pub. Utility Commission v Pennsylvania Electric Co. R-822250 et al. Oct. 14, 1983.

[PA.] A four-CP analysis consisting of two summer and two winter coincident peaks was approved for electric capacity planning used to allocate bulk power supply costs. Pennsylvania Pub. Utility Commission v Metropolitan Edison Co., 60 Pa PUC 349, R-842770 et al., Oct. 24, 1985.

[PA.] Although an electric company was a winter-peaking company, it did participate in a power pool that had summer-peaking companies; therefore, the use of a 12-month coincident peak allocation methodology was reasonable for cost-of-service allocation purposes. Pennsylvania Pub. Utility Commission v Pennsylvania Power & Light Co. (1985) 59 Pa PUC 332, 67 PUR4th 30.

[TEX.] A 12-month coincident peak methodology was found to be appropriate for calculating the jurisdictional allocation of production and demand-related costs where the utility's demand peaks were relatively spread out. Re El Paso Electric Co., 10 Tex PUC Bull 1071, Docket No. 5700, Oct. 26; modified Dec. 7, 1984.

[UTAH] The commission found the digit-month coincident peak method should be used to allocate an electric company's production plant rather than either the single coincident peak method or the average and access demand noncoincident peak method, since the eight-month method: (1) analyzed reserve margins, loss of load probability, and probability of contribution to system peak in determining which eight months to include in the computation; (2) better recognized the design characteristics of the company's system; (3) allowed for recognition of the potential for a shift in the occurrence of peaks; and (4) better reflected the cost causation characteristics of the system and of each individual class. Re Utah Power & Light Co. (1983) 52 PUR4th 436.

[W.VA.] A waiver form the commission requirement that cost apportionment procedures last approved by the commission be used as a guide for subsequent rate cases was granted by the examiner due to the applicant's demonstration that an average of summer and winter peaks more adequately apportioned power production plant and related expenses than the previously used single system peak responsibility allocation method. Re Virginia Electric & Power Co. Case No. 83-343-E-PC, Aug. 12, 1983.

[WYO.] An eight-month coincidental peak method for interjurisdictional allocations of generation and transmission facilities was held to be reasonable for an electric company. Re Utah Power & Light Co. (1985) 66 PUR4th 32.

APPENDIX C
REGULATORY CITATIONS FOR USING
PEAK AND AVERAGE DEMAND ALLOCATIONS FACTORS

[IDAHO] The "peak and average" method (PA) of demand cost allocation represents a refinement of the "average and excess demand" method (AED); under the peak and average method, demand costs are assigned on the basis of a two-part formula that recognizes (1) average use of capacity and (2) responsibility for the total capacity required to meet the maximum system demands; the PA method differs from the AED method, which, in part tow of the formula, recognizes responsibility only for the additional capacity required to meet the maximum system demands. Re Intermountain Gas Co., Case Nos. U-1034-137, U-1034-139, Order No. 20966, Dec. 31, 1986.

[MD.] The four items analyzed by the commission in choosing between different weighings of average demand/peak demand were: (1) the relationship of the allocation to the company's load characteristics; (2) the manner of implementation of the modified peak and base method of allocating power production plant; (3) whether jurisdictional contributions to the company's system coincident peak could be better determined by the average of the four daily coincident peaks or the average of the four monthly coincident peaks; and (4) the time period within which to measure jurisdictional energy usage. Re Delmarva Power & Light Co. 74 Md PSC 566, Case No. 7734, Order No. 66488, Dec. 19, 1983.

[MO.] For allocating fixed generation and transmission costs, the average and peak method, which allocates costs partially on the basis of class contribution to average demand and partially on class contribution to peak demand, was a more appropriate method than the substituted fuel approaches, which recognize certain differences in cost characteristics between base-load units and peaking units and treat all fixed generation costs as quasifuel costs to be allocated to the customer classes on an energy basis. Re Arkansas Power & Light Co. of Little Rock, 25 Mo PSC NS 101, Case No. ER-81-364, April 30, 1982.

[N.M.] The commission accepted the peak and average method for getting rates since it is cost based an provides earnings stability, but the commission also found seasonal pricing to be conceptually appealing since peak and average pricing may improperly allocate some costs to interruptible customers. Re Gas Co. of New Mexico (1983) 56 PUR4th 601.

[N.Y.] The cost of construction of new electric generating capacity or the conversion of existing capacity to burn new fuels should not be allocated entirely to demand; instead considerations of both energy and demand should be made; the choice of a capital-intensive technology and the decision to convert a plant to a less expensive fuel are decisions that are made not only to serve demand but also to meet energy requirements at the lowest economic cost. Re Central Hudson Gas & E. Corp., 86 PUR4th 394, Opinion No. 87-15 (1987).

[N.Y.] In its next general rate case, an electric utility was directed to consider the "average and excess" and average and peak" methods of demand cost allocation. Re Central Hudson Gas & E. Corp., 86 PUR4th 394, Opinion No. 87-15 (1987).

[N.C.Ct.App.] In choosing the method for allocation of demand-related costs, the peak and average system was found to be fair and the resultant increased costs for high-load factor customers is reasonable as they receive the continuing benefit of energy savings from more efficient base-load facilities. North Carolina ex rel. Utilities Commission v. North Carolina Textile Manufacturers Asso., Inc., 59 N.C. App. 240, 296 S.E.2d 487 (1982).

[N.C.] The commission adopted the "summer and winter peak and average" method of cost allocation where it found (1) that the energy-related portion of an electric utility's production plant might approximate th 60 percent of total plant and related expenses allocated by energy under the peak and average method of cost allocation and (2) that both the summer coincident peak and the winter coincident peak should be utilized in allocating the demand-related portion of production plant since they were most representative of the most common and most significant capacity requirements placed on the system. Re Carolina Power & Light Co. (1982) 49 PUR4th 188.

[N.C.] A summer/winter peak and average method was chosen to allocate the cost of electric service between jurisdictions and customer classes, recognizing peak responsibility as the basis for allocating the demand related portion of production plant and the requirement that energy related production plant fixed costs be allocated by kilowatt-hour energy. Re Virginia Electric & Power Co. Docket No. E-22, Sub 273, Dec. 5, 1983.

[N.C.] The "summer-winter peak and average method," by which approximately 40% of production plant and related expenses were allocated based on peak responsibility (the average of summer and witner peak demands), and the remaining 60% of such costs were allocated based on kilowatt-hour consumption, was held to be the most appropriate method for making jurisdictional allocations and for making fully distributed cost allocations in an electric rate case. Re Carolina Power & Light Co., Docket No. E-2, Sub 461, Dec. 7, 1983.

[N.C.] Electric utility cost of service was allocated among jurisdictions and among customer classes using a summer-winter peak and average method whereby 60% of production plant and production related expenses were allocated on the basis of the kilowatt-hour consumption of each class and 40% of such expenses were allocated on the basis of the average contribution of each class to the summer and winter peak demands. Re Carolina Power & Light Co., Docket No. E-26, Sub 481 Sept. 21, 1984.

[N.C.] The summer-winter peak-and-average cost allocation method was found the most appropriate method for making jurisdictional cost allocations and for making fully distributed cost allocations between customer classes of an electric utility; the commission was not convinced that the current rate proceeding was the appropriate forum to change cost allocation methodologies to the twelve coincident peak method. Re Carolina Power & Light Co., 87 PUR4th 64 (1987).

[N.D.] In allocating an electric utility's demand-related costs, the commission rejected the 12-coincident peak (CP) method and the single coincident peak method in favor of an average and peak allocation method, where (1) the utility was incorporated out-of-state and had a system peak in the summer but an in-state-peak in the winter; (2) the 12-CP method would ignore differences in seasonal peaking behavior and dilute the importance of differing jurisdictional peaks for planning purposes; (3) federal approval of the 12-CP method at the wholesale level was not binding on the commission at the retail level; (4) the single CP method would not reflect the impact of off-peak customers who still impose costs on the system; and (5) the average and peak method would recognize both strong peaks and annual average demands. Re Northern States Power Co., 91 PUR4th 305 (1988).

[PA.] Discussion, in electric rate order, of relative merits of average and excess method and peak and average method of allocating electric demand costs. Pennsylvania Pub. Utility Commission v. Pennsylvania Power Co., 85 PUC4th 323 (1987).

[TEX.(P.U.C.)] Statement, in retail electric rate case, that there may be situations when it is appropriate to allocate production capacity costs on the basis of energy use rather than peak demands, such as when a new base load electric plant is constructed to increase fuel diversification instead of meeting new capacity needs; accordingly, in selecting a method for the allocation of electric production capacity costs among customer classes, it is reasonable to use a method that recognizes both peak demand requirements and energy consumption. Re Houston Lighting & P. Co., Tex PUC Bull, Docket Nos. 6765, 6766, Nov. 14, 1986, modified Dec. 4, 1986.

APPENDIX D
REGULATORY CITATION FOR USING
AVERAGE AND EXCESS DEMAND ALLOCATION

[COLO.] Because, a utility was using its less efficient generating plants for peaking purposes thus creating an artificially high demand charge and an artificially low energy charge, the commission ordered a modified average and excess demand rate methodology whereby the average portion would be spread into the energy charge and only the excess portion would be reflected in the demand charge. Re Colordao-Ute Electric Asso., Inc. (1983) 55 PUR4th 331.

[CONN.] The department accepted a cost-of-service study using the average and excess demand methodology, which apportioned production, transmission, and distribution costs into on-and off-peak portions. Re United Illum. Co. (1983) 55 PUR4th 252.

[D.C.CT.App.] An electric utility's use of an average and excess demand cost allocation methodology did not abridge the rights of a rapid transit system customer where the customer failed to demonstrate any adverse impact which would require a change in the cost allocation methodology. Washington Metropolitan Area Transit Authority v. District of Columbia Pub. Service Commission, 486 A.2d 682 (1984).

[D.C.] Based on the assumption that the allocation of costs should be based on the activities which caused them, the commission rejected the peak and average method as inappropriate for the electric company's diversified plant mix of base, cycling, and peaking units; instead, the average and excess demand/noncoincident peak method was held to be reasonable in light of the fact that it recognized that certain classes peaked at times when the entire system did not. Re Implementation of the PURPA Standard for Cost of Service, 3 DC PSC 300, Formal Case No. 758, Order No. 7614, July 23, 1982.

[MD.] A natural gas distributor's average and excess demand method for allocating transmission plant was approved because by taking a weighted average of both peak day demand and annual sales, the distributor was reflecting the plant's demand-related costs as well as total system movement for both pipeline and peaking gas. Re Washington Gas Light Co., 77 Md PSC 30, Case No. 7649, Order No. 67286, Feb. 10, 1986.

[PA.] It is acceptable to use an average and excess demand methodology in allocating demand-related production plant and expenses because it prevents off-peak customers and customers with fluctuating loads from benefiting from plant paid for by others and because a coincident peak method would not provide stable allocation factors but would be skewed by the few customers with very large loads. Pennsylvania Pub. Utility Commission v. Duquesne Light Co., 59 Pa PUC 67, R-842583 et. al., Jan. 24, 1985.

[ME.] In allocating demand-related production and transmission costs, reliance on coincident peak allocations is improper because the CP method ignores the demand of off-peak customers who do impose costs on the system, and an allocation method that is both time differentiated and allocates generating plant on the basis of average demand or energy should be used instead. Re Central Maine Power Cp. (1985) 69 PUR4th 564.

[MD.] There was not compelling reason to change an electric company's jurisdiction cost allocation methodology from the average and excess demand method to the average and peak method to the average and peak method where: (1) consistency among retail jurisdictions regulating the company, while not be itself sufficient to warrant the use of a particular methodology, would avoid the possibility that the use of different methodologies would result in over or under recovery of total costs and (2) the two methodologies presented did not produce significantly different results. Re Potomac Electric Power Co. 74 Md PSC 329, Case No. 7597 Phase II, Order No. 66305, Aug. 1, 1983.

[TEX.] A stipulated cost allocation methodology based on the average and excess demand with four coincident peaks method was found to be the most appropriate. Re Houston Lighting & P. Co. (1982) 8 Tex PUC Bull 75, 50 PUR4th 157.

[TEX.] An average and excess demand methodology was found to be appropriate for calculating the interclass production plant and transmission cost allocation. Re El Paso Electric Co., 10 Tex PUC Bull 1071, Docket No. 5700, Oct. 26, 1984; modified Dec. 7, 1984.

[TEX.(P.U.C.)] In general, the electric transmission plant costs should be allocated among customer classes using the same allocation factors as for electric production (demand or capacity) costs; however, in retail electric rate case, where the "probability of a negative margin" (PONM) method was adopted to allocate production costs, which was inappropriate for allocating transmission costs, it was held reasonable to employ the four coincident peak average and excess method (4-CP A&E) to allocate electric transmission costs among customer classes. Re Houston Lighting & P. Co., Tex PUC Bull, Docket Nos. 6765, 6766, Nov. 14, 1986, modified Dec. 4, 1986.

APPENDIX E
REGULATORY CITATIONS FOR
SEPARATE RECOGNITION OF DISTINCT LOADS

[COLO.] Cost of service for the central transmission system of an electric utility was allocated by use of the average and excess demand method, with no excess demand assigned to interruptible and curtailable customers; cost of service for other transmission facilities and distribution substations was allocated based on a separate average and excess demand with no excess for interruptible and curtailable customers. Re Public Service Co. of Colorado (1985) 68 PUR4th 363.

[F.E.R.C.] Where one of an electric company's tariffs specifically stated that a request for load reduction might be made during on-peak hours to avoid a new system peak, thus allowing the company to avoid the demands that a new peak would impose, the commission determined that the tariff's loads were interruptible and should not be included in determining the percentage responsibility of each class under the 12-coincident peak demand cost allocation method. Re Delmarva Power & Light Co. (1983) 24 FERC 61,199,55 PUR4th 31, Opinion No. 185.

[IDAHO] Adjustments to an electric utility's calculation of a large interruptible customer's normalized demand, energy, and interruptibility resulted in a reduction in the retail jurisdictional demand allocation factor. Re Idaho Power Co., 76 PUR4th 326 (1986).

[IDAHO] The commission accepted a jurisdictional allocation factor that adjusted for transmission losses for the Washington-Idaho jurisdiction power interchange, finding that the effect of not including transmission losses in this interchange was to assign transmission losses from this net power flow into Washington entirely to the Idaho jurisdiction, and rejected as unpersuasive the utility's argument that a change in the jurisdictional allocation factor should be delayed until its next filing because hearings before the Washington commission had been completed since the company was not precluded from requesting modification of its jurisdictional allocation factors in other jurisdictions. Re Washington Water Power Co. (1984) 58 PUR4th 126.

[IDAHO] The commission accepted a proposed reduction of the jurisdictional allocation of production and transmission plant to give ratepayers the benefit of adjustments for transmission losses. Re Washington Water Power Co. (1985) 65 PUR4th 100.

[IDAHO] The interruptible nature of an irrigation load provides a resource to the power company at the expense of the irrigation class;

therefore, for the purpose of performing a jurisdictional demand cost allocation using the 12-month coincident peak method, it is appropriate to benefit the irrigator class through a downward adjustment of the system and jurisdictional monthly coincident peaks to reflect the load the company could have shed under the irrigation load program. Re Utah Power & Light Co. (1984) 63 PUR4th 13.

[IND.] In an electric rate proceeding, it was found reasonable to recognize the inferiority and consequent lower costs of interruptible service, specifically, the commission found it reasonable to reduce 75% the sum of the 12 monthly coincident peak demands for the interruptible customer class in determining the demand cost allocation factor for the class. Re Northern Indiana Pub. Service Co., 85 PUR4th 605 (1987).

[MD.] Although an electric utility had traditionally used an average and excess demand (AED) method for allocating jurisdictional production system costs, it was found more appropriate for the utility to begin using an average and peak (A&P) method based on a four-coincident peak factor, because the utility was operating under vastly different circumstances that it had been when AED had been authorized originally, as the utility had sold off its out-of-state operations, and the A&P method was seen as promoting greater stability now that the utility had more homogenous system peaks and demand. Re Potomac Electric Power Co., 83 PUR4th 219 (1987).

[MINN.] A gas distribution company's interruptible service customers should bear some of the company's demand related costs where the interruptible customers' service is curtailed relatively infrequently and the interruptible service results in expense to the company system on an almost year-round basis. Re Northern States Power Co., 73 PUR4th 395 (1985).

[OHIO] A company could not treat its interruptible customers as if they were firm customers for cost allocation purposes; therefore, a proposal to allocate production plant to interruptible customers was denied, but transmission capacity was permitted to be allocated to those customers. Re Columbus & Southern Ohio Electric Co. (1982) 50 PUR4th 37.

[OHIO] With the exception of interruptible service customers governed by private contract, the production-related items of an electric utility's authorized revenue increase should be allocated among customers using a four-coincident peak method where the utility has a summer peaking system and the 4CP method would better reflect cost causation. Re Cleveland Electric Illum. Co., Case No. 85-675-EL-AIR, June 24, 1986.

[VA] For rate design purposes, a cost of service study was adopted for a gas utility that included the allocation of demand costs to interruptible sales and transportation classes, with the commission noting that the study made evident the subsidy of the residential class by the interruptible and transportation classes and stating that it was imperative that rates of return for rate classes should move toward parity. Re Commonwealth Gas Services, Inc., 88 PUR4th 533 (1987).

[VA.] It was appropriate to assign some demand costs to the interruptible customers of a natural gas distribution utility. Re Lynchburg Gas Co., 95=2 PUR4th 366 (1988).

[WASH.] It was held that fixed costs i.e., contract charges based on a gas distributor's system peak requirements should be shared by all classes that use gas delivered through the pipeline, including interruptible customers, because of the difficulty caused by customers that switch to interruptible service after costs have been incurred, due to less expensive alternate fuel. Washington Nat. Gas Corp., 84 PUR4th 119 (1987).

APPENDIX F
REGULATORY CITATIONS ON USING STATISTICAL METHODS FOR COST ALLOCATIONS

[COLO.] A proposal by the commission staff to allocate demand costs for electric rates by use of an ABC method that would break down the test year into 8,760 hours and would assign embedded costs on an hourly basis, by functionalizing production costs by use of each production unit in the system, was rejected, because of difficulties that would be incurred in implementing the method and because of the proprietary nature of the ABC method; a proposal by the electric utility to continue use of the noncoincident peak average and excess demand method was adopted with a statement that the commission would encourage continued development of the ABC method for presentation in a future docket. Re Public Service Co. of Colorado (1985) 68 PUR4th 363.

[KY.] Where a utility's embedded production and transmission costs were caused by factors in addition to system peak demand, the commission believed that these costs should be allocated to the customer classes based on the factors that caused the investments in capacity and, thus, rejected a cost-of-service study that allocated production and transmission capacity costs on the basis of contribution to system coincident peak in favor of a study that allocated the capacity costs to costing periods and then to customer classes on the basis of average demand or energy. Re Louisville Gas & E. Co. Case No. 8616, March 2, 1983.

[MASS.] The department ruled that the peak and average method was appropriate for the allocation of demand-related power supply costs for an electric company with a strong peak, which in the recent past had consistently occurred in the same season, and that the additional degree of accuracy, which might be obtained from a proposed plant-by-plant analysis, was unnecessary for the determination of class revenues, since considerations of rate continuity prevented the department from achieving equal rates of return in the proceeding. Re Boston Edison Co. (1984=3) 53 PUR4th 349.

[MASS.] In selecting an allocation method for demand-related production costs in retail electric rate case, it must be recognized that not all capital costs (costs incurred to construct a generating plant) are demand related e.g., the relatively high capital costs of a new base-load plant may represent capitalized energy costs, because the capital costs are justified only by the energy savings of the new plant; moreover, the relatively low capital costs of peaker plants may represent capitalized demand costs, because peaking plants are operated almost exclusively to meet load during peak periods; therefore, the costs of base-load units should be allocated to the customers who take service during the hours that such plants are operated, and the POD ("probability of dispatch") method of demand cost allocation meets such criteria, and is preferred over the "AED/12 CP" method (the average and excess demand method, using class contributions to 12 monthly peaks), because the AED/12 CP method fails to distinguish between base-load and peaking plants. Re Western Massachusetts Electric Co., 80 PUR4th 479 (1986).

[MASS.] As part of an electric utility's retail cost-of-service study, the utility used the probability of dispatch (POD) capacity allocator to allocate a portion of its transmission costs, even though there was no evidence that the POD allocation was appropriate for allocating transmission plant and expenses; because the utility had not explained its reason for using a POD capacity allocator for portions of its transmission costs, even though transmission expenses are deemed to be more closely related to peak demands than to energy use, the utility was ordered, in its next rate case, to use a transmission allocator that more closely reflected transmission costs. Re Western Massachusetts Electric Co., 87 PUR4th 306 (1987).

[MASS.] The department approved an electric utility's use of a "probability of dispatch modified peaker method" for its retail cost-of-service study, which segregated pure capacity costs and allocates them only to peak periods, resulting in an attempt to assign pure capacity costs to those users who have caused their incurrence. Re Western Massachusetts Electric Co., 87 PUC4th 306 (1987).

[MASS.] A gas utility's pipeline demand charges were ordered allocated in accordance with the proportional responsibility method, which ranks all months in ascending order by total monthly normal consumption and determines the increment by which normal consumption in a given month exceeds that in the next-ranked month, as well as the total number of months whose normal consumption equals or exceeds that of the month in question. Re Essex County Gas Co., 88 PUR4th 167 (1987).

[MASS.] Statement, in electric rate case, that detailed information about system and class loads in each hour is a necessary input for the probability of dispatch cost allocation method. Re Western Massachusetts Electric Co., 93 PUR4th 550 (1988).

[MASS.] The allocation of production plant costs among rate classes using a modified-peaker probability of dispatch method was accepted as reasonable in determining the rate structure of an electric utility; the method allocates a generating unit's capacity costs and energy costs over all hours in which a unit operates and, in turn, allocates those costs to customers consuming electricity during those hours, in proportion to their load during those hours. Re Western Massachusetts Electric Co., 93 PUR4th 550 (1988).

[MASS. Sup. Jud. Ct.] In reviewing a retail electric rate order, the court affirmed the portion of the order that had adopted the probability of dispatch (POD) method for the allocation of electric generation and transmission costs even though the POD methodology differed from the methodology applied by a systems agreement governing the allocation of the integrated utility system to which the utility belonged; it was found that inasmuch as substantial evidence supported the determination that POD methodology would equitably allocate generation and transmission costs, the court was not empowered to overturn that determination. Monsanto Co. v. Massachusetts Dept. of Pub. Utilities, 402 Mass. 564, 94 PUR4th 533, 524 N.E.2d96 (1988).

[MO.] The commission accepted the additional cost (time-of-use) method as theoretically the most appropriate method of allocating transmission costs since it was designed to consider the mix of plants with varying characteristics in terms of fixed and variable costs; however, the commission adopted the average and peak method as the most practical method which provided the most reasonable alternative to the time-of-use procedure. Re Kansas City Power & Light Co. (1983) 25 Mo PSC NS 605, 53 PUR4th 315.

[MO.] The time-of-use method was deemed the most reasonable method for allocating the production costs of serving various classes because it does not rely on the concept of generation capacity costs as being fixed but does recognize the class contributions that are made to both system peak demands. Re Union Electric Co. (1985) 27 Mo PSC NS 183, 66 PUR4th 202.

[NEV.] "Loss of load probability" is the likelihood that load or demand will exceed the utility's capacity to serve that load, and it is a method of allocating demand costs among classes of customers, but more than one year of LOLP data is required. Re Sierra Pacific Power Co., 73 PUR4th 306 (1985).

[N.J.] An electric utility was ordered to use an hourly production plant method for allocating costs among classes of customers because the method allocated the costs of a plant only for the hours when the plant was expected to operate and thereby more accurately reflected the economics of system planning, because the method computed the average variable operation and maintenance costs on an hourly basis and thereby more directly matched costs and benefits to each customer class, and because the method recognized both peak demand reliability and year-round energy consideration and therefore was consistent with the internal standards of the board of public utilities and with the requirements of the Public Utility Regulatory Policies Act. Re Atlantic City Electric Co., 71 PUR4th 571 (1986).

[N.J.] An hourly production plant cost method was reaffirment forte allocation of an electric utility's system generation costs where it was found that the method would not produce and all-energy apportionment of costs, but would send more accurate time differential price signals and would better match cost causers with cost payers than would an average and peak methodology. Re Atlantic City Electric Co., 83 PUR4th 612 (1987).

[N.Y.] Discussion of "probability of negative margin" (PONM) method of allocating electric generation capacity costs, whereby embedded capacity costs are allocated to service classification hour-by-hour, based upon relative demands, for all hours in which the statistical probability that loads will exceed available capacity is equal to or greater than .001%. Re Niagara Mohawk Power Corp., 83 PUR4th 97. Opinion No. 87-3 (1987).

[N.C.] The so-called "production-stacking" method represents a good faith effort to quantify the amount of fixed costs for base-load electric plants that might be classified as energy related and, as such, represents a useful tool for comparing the cost allocation methods for electric ratemaking purposes. Re Carolina Power & Light Co., Docket No. E-2, Sub 461, Dec. 7, 1983.

[TEX. (P.U.C.)] In a cost of service study in an electric rate case, the probability of a negative margin (PONM, or "Probability Peak") method was adopted for the purpose of allocating production capacity costs among customer classes, because it was necessary to recognize both peak demand requirements and energy consumption in allocating costs incurred to build new plant; the capital substitution method (CAPSUB), which would have allocated capacity costs on the basis of energy use to a greater extent, was rejected; the four coincident peak method (4-CP) was rejected because it would allocate not production costs to the street, protective, and guard lighting classes. Re Houston Lighting & P. Co. Tex PUC Bull, Docket Nos. 6765, 6766, Nov. 14, 1986, modified Dec. 4, 1986.

APPENDIX G
STATISTICAL ALLOCATION TO CLASS

Load Definition	Class	Average Load	Period Allocation	Statistics As Cost	Statistics As Price
High Load	Residential	500 mw	50.00%	16.304%	18.383
7 or 100 Hours	Commercial	300 mw	30.00%	9.738	11.029
Statistics = .1	Industrial	200 mw	20.00%	6.522	7.353
	Street Lighting	0 mw	0.00%	.000	.000
Subtotal		1000 mw	100.00%	32.609%	36.765
Medium Load	Residential	400	47.62%	31.057%	29.413
7 or 200 Hours	Commercial	250	29.76%	19.410%	18.381
Statistics = .01	Industrial	190	22.62%	14.752%	13.971
	Street Lighting	0	0.00%	0.000%	0.000
Subtotal		840	100.00%	65.219%	61.765%
Base Load	Residential	201	33.45%	.726	.492
7 or 6.660 Hours	Commercial	157	26.45%	.567	.384
Statistics = .001	Industrial	177	29.45%	.640	.433
	Street Lighting	66	10.98%	.239	.161
Subtotal		601	100.00%	2.172%	1.470%
Total	Residential			48.087%	48.288%
Year	Commercial			29.760%	29.794%
	Industrial			21.914%	21.757%
	Street Lighting			.239%	.161%
TOTAL				100.000%	100.000%

APPENDIX H
REGULATORY CITATIONS ON
DISTRIBUTION CLASSIFICATION AND ALLOCATION

[CAL.] A marginal cost approach should be adopted for the allocation of electric customer costs; an embedded cost approach would be no more appropriate for the allocation of customer costs than for the allocation of electric demand and energy costs. Re Pacific Gas & Electric Co., 77 PUR4th 389 (1986).

[CAL.] A decremental cost approach for allocating electric customer costs (which would measure those costs that the utility would not incur if an existing customer were to leave the utility system) is unacceptable standing alone, because any costs imposed by new customers that exceeded the decremental cost would be allocated on a demand basis unless there was a hookup fee or connection charge, and would result in a shifting of costs from one customer class to another. Re Pacific Gas & Electric Co., 77 PUR4th 389(1986).

[CAL.] In theory, the best method of measuring marginal electric customer cost, and of allocating customer costs among electric customer classes, is to measure such costs according to a weighted average of the incremental cost for new customers and the decremental cost for existing customers; in practice a conservative estimate of incremental customer costs was adopted as a reasonable proxy; in future cases, the commission would rely upon the weighted average of incremental and decremental cost. Re Pacific Gas & Electric Co., 77 PUR4th 389 (1986).

[D.C.] An argument that an electric company's distribution plant should be classified as entirely demand related was rejected and instead distribution plan was allocated both demand and customer costs. Re Implementation of the PURPA Standard for Cost of Service, 3 DC PSC 300, Formal Case NO. 758, Order NO. 7614, July 23, 1982.

[ME.] When allocating distribution plant between demand and customer components, it is appropriate to include in customer charges the costs of a minimum-sized distribution system, and such will not be unfair to low-usage customers, as the customer charge is not designed to reflect each customer's minimum demand but is to cover the costs of the system designed to meet minimum safety and service requirements. Re Central Main Power Co. (1985) 69 PUR4th 564.

[MD] In a municipality where the law requires that all wiring for new housing developments of 20 units or more be placed underground the major portion of the excess cost of undergrounding should be borne by the home builders as charge per lot for the installation of the underground facilities, since, from an aesthetic viewpoint, a house will be more valuable, but, because of the advantages of safety and freedom of interruption from service, a portion of the excess cost may be fairly included in the rate base of the electric company. Suburban Maryland Home Builders Assoc. v Potomac Electric Power Co. (1968) 72 PUR3d 282.

[MD.] Allocation of the demand component of the company's investment in primary distribution lines should reflect only the excess of class maximum demands over the demands that can be served by the minimum distribution system. Re Delmarva Power & Light co. 74 Md PSC 566, Case No. 7734, Order No. 66488, Dec. 19, 1983.

[MD.] It is appropriate to allocate distribution services cost using a customer component and a demand component based upon the smallest sized main installed in a natural gas utility's system. Re Washington Gas Light Co., 77 Md PSC 30, Case No. 7649, Order NO. 67286, Feb. 10, 1986.

[MD.] A gas utility's meter removal and resetting costs were allocated on the basis of the number of the utility's customers without regard to the customer's size or consumption, where there was no evidence that larger customers required reset meters any more frequently than smaller customers. Re Washington Gas Light Co., 77 Md PSC 30, Case NO. 7649, Order no. 67286, Feb. 10,1986.

[N.Y.] Distribution costs should be allocated generally on the basis of noncoincident demand, segregating part of the system as the minimum distribution network from the other portions of the low-tension distribution system. Re Consolidated Edison Co. of New York, Inc. (1975) 8 PUR4th 475, Opinion 75-9.

[N.Y.] The allocation of electric service customer costs based on a system with minimal capacity was upheld. Re Rochester Gas & E. Corp. (1985) 8 PUR4th 475, Opinion NO. 85-13.

[N.C.] The "minimum system technique" is a method for allocating a portion of distribution plant of an electric utility between customer classes, and derives the cost of distribution plant as if all components of such plan are "minimum" size, which means the minimum size needed to connect each customer to the system regardless of the among of kilowatt-hours used; the commission found it inappropriate to discontinue the use of this system. Re Carolina Power & Light Co., 87 PUR4th 64 (1987).

[PA.] In assessing the costs of distribution plant, it must be recognized that certain planning, construction, and operational costs will have no relationship to the minimum or maximum capacity required for service, and therefore it is appropriate to allocate distribution plant costs on a demand-customer basis. Pennsylvania Pub. Utility Commission v. Duquesne Light Co., 59 Pa PUC 67, R842583 et al., Jan 25, 1985.

[PA.] It is valid to allocate electric distribution plant costs on a customer-demand basis, employing a minimum grid system approach. Pennsylvania Pub. Utility Commission v. Metropolitan Edison Co., 60 Pa PUC 349, R842770 et al., Oct. 24, 1985.

[R.I.] Distribution costs were included in a fixed cost customer charge by allocating such distribution costs on the basis of customer usage, rather than on a pro rata basis. Re Newport Electric Corp. (1980) 34 PUR4th 526.

[S.D. Sup. Ct.] It was not arbitrary and capricious for the state commission to have allocated transmission plant and expenses using a 9-2 weighted average of demand and mileage factors, even though other testimony supported a 4-6 weighted average of demand and mileage, since the omission's decision was based upon substantial evidence. South Dakota Pub. Utilities Commission v Otter Tail Power Co. (1980) 291 NW2d 291.

[TEX.(P.U.C.)] In a cost of service study in an electric rate case, the costs that are classified as customer-related are those costs incurred by the utility as the result of a customer's existence on the system, regardless of the quantities of demand or energy that are imposed or consumed, or when such quantities occur; examples of customer-related costs include bill preparation, service drops and meter readings. Re Houston Lighting & P. Co., — Tex PUC Bull — Docket NO. 6765, 6766, Nov. 1986 modified Dec. 4, 1986.

[UTAH] The commission rejected the use of a minimum distribution system for classifying distribution costs, since that system would result in a double allocation of these costs to low-customers, but found that it would be reasonable, now and the future, to classify each distribution system account as demand cost or customer cost, based upon engineering analysis. Re Utah Power & Light Co. (1983) 52 PUR4th 436.

HERBERT J. VANDER VEEN

Mr. Vander Veen is a Partner in the Washington office of the Ernst & Young Utility Group. He has extensive experience in the areas of administration, rate design, cost analysis, contracts, pricing, computer applications, load studies, research surveys, economic studies, accounting, and the establishing of terms and conditions for utility service. The following is a representative list of the consulting assignments that Mr. Vander Veen has directed for preparation and presentation before regulatory authorities in electric, gas, and water and sewer companies.

Electric Cost of Service and Rate Design:

State

Upper Peninsula Power Company
Northwestern Public Service Company
Indianapolis Power & Light
Tampa Electric Company
Maine Public Service Company
Savannah Electric & Power Company
El Paso Electric
Montana Dakota Utilities Company
Edison Sault Electric
Consumers Power Company
Jamaica Public Service Corporation
Duquesne Light
Tucson Electric Company
Green Mountain Power Company
Southwestern Electric Service Company
Otter Tail Power Company
Nova Scotia Power Company
Alaska Public Utilities Commission
Community Public Service Company
Seattle City Light
Direct Industrial Customers of BPA
Nantahala Power & Light
Tapoco Inc.
Central Illinois Public Service Company
Sierra Pacific Power Company
Washington Metro Area Transit Authority
Aluminum Company of America
Delmarva Power & Light
Manitoba Hydro

Federal

Tampa Electric
Gulf States Utilities
Indianapolis Power & Light
Upper Peninsula Power Company
Edison Sault Electric
Northwestern Public Service Company
El Paso Electric
Eastern Utilities Associates

Gas Cost of Service Studies and Rate Design:

Gas Metropolitan Inc.
Northwestern Public Service
Commonwealth Gas Services
Connecticut Natural Gas
Commonwealth Gas Transmission
Alabama Gas Corporation
Montana-Dakota Utilities
Mobile Gas Service Corporation
Valley Gas Company
Haverhill Gas Company
Atlanta Gas Light
El Paso Natural Gas Company
El Paso Alaska Company
Interstate Power Company
Louisiana Resources
Faustina Pipeline
Louisiana Intrastate Gas Company
Williams Natural Gas Company
Trans Louisiana Gas Company
Sierra Pacific Power Company
Syracuse Suburban Gas Company
Gas Service Inc.
Indicated Agricultural Consumers of Oklahoma
Fuels Inc.
Agrico Chemical Company
Memphis Light, Gas & Water
Southern Natural Gas
Arkla, Inc.
Oklahoma Natural Gas
Consumers Gas Company LTD
Northwestern Utilities LTD
Southern Natural Gas Transmission
Columbia Gas Transmission
Columbia Gulf Gas Transmission
Transco
Northwestern Utilities Ltd.
Canadian Western Natural Gas Ltd.

REMC Cost Analysis and Rate Design:

Tri State
Dairyland
East Kentucky

Steam Cost of Service Studies and Rate Design:

Upper Peninsula Power Company
Indianapolis Power & Light
Nova Scotia Power Corporation

Water Cost of Service Studies and Rate Design:

Clear Lake Water Authority
Suffolk County Water Authority

Revenue Requirements and Financial Analysis:

Tampa Electric
Connecticut Natural Gas
Nova Scotia Power Corporation
Indianapolis Power & Light
El Paso Electric
Haverhill Gas Company
Valley Gas Company
Alabama Gas Corporation
Mobile Gas Service Corporation
Montana Dakota Utilities
Edison Sault Electric
Tucson Electric Company
Sierra Pacific Power Company
El Paso Alaska Company
Faustina Pipeline Company
Louisiana Resources Company
Williams Natural Gas Company
Trans Louisiana Gas Company
The Williams Companies

General Utility Economic, Regulatory, and Acquisition Studies:

Florida Power & Light
Phillips Petroleum Company
Tenneco Inc.
Connoco Inc.
Pennzoil Inc.
Arizona Nuclear Power Project
Reynolds Metals Company
Aluminum Company of America
The Williams Companies
CSX
Trans Louisiana Gas Company
Williams Natural Gas Company
El Paso Natural Gas
Arkla, Inc.
Northwest Pipeline Company
Union Gas Company
Consumers Gas Company LTD
Cities Service Gas Company
Northwest Pipeline Company
Mississippi River Gas Transmission

General Utility Economic, Regulatory, and Acquisition Studies: (Cont.)

Texas Gas Transmission
ARKLA-South Texas
Palm Beach Public Utilities Corporation

General Advisory Services

Royalty Allocations – Gas Plant Liquids Allocation
Price Settlement – San Juan Natural Gas Overriding Royalty Valuation Cost to produce and transport Alaskan LNG
Gas Contract Abrogation – Calculation of contract damages for natural gas

Indirect and overhead cost allocations
RM85-1
Coal Gasification
Alaskan LNG
General Applications of the NGPA
Production and cost analyses
R-479 – Natural Gas Producers – Wellhead pricing of gas
R-389 – Natural Gas Producers – Wellhead pricing of gas
RM75-14 – Natural Gas Producers – Wellhead pricing of gas
RM86-3 – Replacement cost of gas – Lower 48 United States

In addition, Mr. Vander Veen has assisted the above clients and several others in conducting cross-examination of intervenor witnesses, the preparation of briefs, and general rate case presentation of limited issues.

Mr. Vander Veen has considerable testimony experience (see attached). He has also assisted clients in the preparation of testimony and exhibits in Pennsylvania, Wisconsin, New Mexico, Virginia, Georgia, Rhode Island, Nevada, California, Illinois, and the provinces of Ontario and Quebec, Canada.

Prior to joining Ernst & Young, Mr. Vander Veen was employed as the manager of the Rate Department at Michigan Consolidated Gas Co. and as a rate analyst with Consumer's Power Company. During his employment at these two utilities, his experience included gas and electric utility rate design, cost allocation, steam service rates and costs, load studies, computer applications, acquisitions, economic evaluations, gas purchase and production contracts, gas rate and curtailment proceedings before the Federal Power Commission, weather normalization, and other related rate and economic analysis. Mr. Vander Veen was also employed for ten years by Stone & Webster Management Consultants where he performed many of the same services and conducted similar studies.

Mr. Vander Veen has an AB in economics from Calvin College and is a member of the American Gas Association.

ATTACHMENT A

HERBERT J. VANDER VEEN

TESTIMONY EXPERIENCE

CLIENT	JURISDICTION	DOCKET	YEAR
Upper Peninsula Power Company	Michigan	3297	1970
Tucson Gas and Electric	Arizona	41692	1971
Indianapolis Power and Light Company	Indiana	32402	1971
Tampa Electric Company	Florida	70532	1971
Mobile Gas Service Corporation	Alabama	16570	1972
Edison Sault Electric Company	Michigan	3563	1972
Tucson Gas and Electric	Arizona	42123	1972
Connecticut Natural Gas Corporation	Connecticut	11321	1973
Edison Sault Electric Company	FPC	7803	1973
Alabama Gas Corporation	Alabama	16814	1974
Indianapolis Power and Light Company	Indiana	33735	1974
Tucson Gas and Electric	Arizona	44853	1974
Connecticut Natural Gas Corporation	Connecticut	11486	1974
Montana Dakota Utilities	North Dakota	9060	1975
Montana Dakota Utilities	North Dakota	9082	1975
Montana Dakota Utilities	Montana	6277	1975
Connecticut Natural Gas Corporation	Connecticut	11710	1975
Haverhill Gas Company	Massachusetts	18261	1975
Montana Dakota Utilities	South Dakota	3052	1975
Haverhill Gas Company	Massachusetts	18261A	1975
Indianapolis Power and Light Company	Indiana	34363	1976
Mobile Gas Service Corporation	Alabama	17164	1976
Alaska Public Utilities Commission	Alaska	U76-53	1976
Nova Scotia Power Corporation	Nova Scotia	———	1976
Community Public Service Company	Texas	178	1977
Nova Scotia Power Corporation	Nova Scotia	———	1977
Southwestern Electric Company	Texas	178	1977
Tampa Electric Company	Florida	760846-EU	1977
Connecticut Natural Gas Corporation	Connecticut	770902	1978
Connecticut Public Util. Control Auth.	Connecticut	780402	1978
Nova Scotia Power Corporation	Nova scotia	———	1978
Connecticut Natural Gas Corporation	Connecticut	781110	1979
Louisiana Intrastate Gas Corporation	Louisiana	U-13172	1979
Syracuse Suburban Gas Company	New York	27540	1979
Washington Metro Area Transit Auth.	District of Columbia	715-1	1980
Connecticut Natural Gas Corporation	Connecticut	791202	1980
TAPOCO	FERC	ER-76-828	1980

ATTACHMENT A (Cont.)

CLIENT	JURISDICTION	DOCKET	YEAR
TAPOCO	FERC	EL-78-18	1980
Tampa Electric	Florida	800011-EU	1980
Commonwealth Gas Services	Virginia	PUE-800110	1981
TAPOCO	North Carolina	E-13-Sub29	1981
Nantahala Power & Light	North Carolina	E-13-Sub35	1981
Direct Service Ind. of B.P.A.	BPA/FERC	——	1981
Indicated Agricultural Consumer	Oklahoma	27347	1981
Connecticut Natural Gas Corporation	Connecticut	811212	1982
Indianapolis Power and Light Company	Indiana	36538	1982
Reynolds Metals Company	Arkansas	81-144-U	1982
Aluminum Company of America	North Carolina	E-13-Sub35	1982
Faustina Pipe Line Company	Louisiana	82-105	1982
Louisiana Resources Company	Louisiana	82-106	1982
Indianapolis Power & Light	Indiana	36880	1982
Nova Scotia Power Corporation	Nova Scotia	——	1982
Faustina Pipe Line Company	Louisiana	82-291	1982
O.F.M.A.	Oklahoma	27812	1982
Connecticut Natural Gas	Connecticut	82-01-01	1983
O.F.M.A./Interim	Oklahoma	28069	1983
O.F.M.A.	Oklahoma	28291	1983
Agrico Chemical Company	Arkansas	83-161-U	1983
Agrico Chemical Company	Arkansas	83-121-C	1983
Consolidated Edison Company of NY, Inc.	FERC	RP82-55	1984
Connecticut Natural Gas Company	Connecticut	84-02-09	1984
Cyprus Pima, et al	Arizona	U-1933-83-238	1984
Agrico Chemical Company	Arkansas	85-043-U	1985
Indianapolis Power & Light Company	Indiana	37837	1985
Tri-County Gas Company	Virginia	PUE 850044	1985
Columbia Nitrogen Corporation	Georgia	3524-U	1985
W.R. Grace	Tennessee	——	1985
Nova Scotia Power Corporation	Nova Scotia	——	1986
Big Rivers Electric Corporation	Kentucky	9613	1986
Commonwealth Natural Gas	Virginia	PUE 860031	1986
Columbia Nitrogen- NIPRO	Georgia	3582-U	1986
Columbia Nitrogen- NIPRO	FERC	RP86-63-000	1986
Columbia Nitrogen- NIPRO	FERC	RP86-114-000	1986
Philadelphia Gas Works	FERC	TA 86-1-29 et al	1987
Philadelphia Electric Company	FERC	TA 86-1-29 et al	1987
Consumers Gas/Union Gas	NEB-Canada	GHR-1-87	1987
Columbia Gas Transmission Corporation	FERC	RP86-168-000	1987
Columbia Gulf Transmission Company	FERC	RP86-167-000	1987
Commonwealth Natural Gas	Virginia	PUE 870083	1987
Connecticut Natural Gas	Connecticut	87-08-20	1987
Sun Marketing Refining/Columbia Gas Transmission Corporation	FERC	RP86-168-000 TC86-21-000	1987
Sun Marketing Refining/Columbia Gulf Transmission Corporation	FERC	RP86-167-000	1987

ATTACHMENT A (Cont.)

CLIENT	JURISDICTION	DOCKET	YEAR
Connecticut Natural Gas	Connecticut	87-08-20	1988
Manitoba Hydro	Manitoba	———	1988
Northwestern Utilities LTD	Alberta		1988
Columbia Nitrogen	FERC	RP87-17-000	1988
Nova Scotia Power Corporation	Nova Scotia	———	1989
Manitoba Hydro	Manitoba	———	1989
Connecticut Natural Gas	Connecticut	89-02-09	1989