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NWTPC COST OF SERVICE REVIEW - DECEMBER 1991

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NWTPC COST OF SERVICE REVIEW

DECEMBER 1991

A REPORT OF THE PUBLIC UTILITIES BOARD

RESPECTING

THE PROPOSED COST OF SERVICE METHODOLOGY

OF THE NORTHWEST TERRITORIES POWER CORPORATION

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EXECUTIVE SUMMARY

In accordance with a directive from the Executive Council of the Government of the Northwest Territories (GNWT), the Public Utilities Board (the Board) conducted a review into the cost of service methodology proposed by the Northwest Territories Power Corporation (NWTPC).

A public hearing was held in Yellowknife on October 29-30, 1991. The Board received comments from the electrical utilities, interested parties and a representative from the GNWT. The Board also received assistance from a cost of service consultant.

A cost of service study enables a utility to determine its costs to provide service to its customer groups and usually proceeds through functionalization, classification and allocation stages.

With respect to functionalization, the Board is satisfied with NWTPC's continued use of the Production (Generation), Transmission, Distribution and General and Common groupings to functionalize its capital assets and operating expenses.

At present, the Board is satisfied with NWTPC'S proposed classification of its generation, transmission and distribution facilities and its general and common expenses. The Board anticipates NWTPC will be in a position at a future General Rate Application to support its classification methods.

The Board is generally satisfied with NWTPC's proposed allocation methods for its generation, transmission and distribution facilities and its general and common expenses.

The Board recommends, however, that NWTPC develop information regarding the coincident peak demands of the customer classes on its system and develop estimates of the class non-coincident peaks.

The Board recommends that NWTPC begin to develop information with respect to plant or community-level costs. Such cost information is necessary for the determination of maintenance schedules, for capital planning and to enable NWTPC to target conservation efforts towards high-cost, high-usage customers.

The Board recommends that NWTPC implement a standard system of accounts to facilitate the collection of information necessary for NWTPC to meet its regulatory requirements.

The Board's concern with respect to the schedule of events proposed by NWTPC is that NWTPC develop and file submissions which are complete and represent its considered positions. The Board expects NWTPC to support its proposals at future General Rate Applications.

Section 1 INTRODUCTION

On April 8, 1991, pursuant to the provisions of Sections 14 (1) and56 (1) of the Public Utilities Act (the Act), the Executive Council of the Government of the Northwest Territories (GNWT) and the Minister responsible for the Public Utilities Board (the Board) directed the Board to conduct a public review of the cost of service methodology proposed by the Northwest Territories Power Corporation (NWTPC, the Corporation).

The Terms of Reference under which the review was to be conducted are set forth in Appendix A. The Terms of Reference were amended by letter from the Minister responsible for the Board dated July 25, 1991 to permit a public hearing on October 29-30, 1991 and to revise the report date to December 1, 1991.

The Board was directed to provide a written report to the Executive Council, and in that report include an analysis of the proposed NWTPC cost of service methodology. If changes were found to be advisable, the Board was directed to identify those changes needed to achieve an acceptable cost of service methodology.

Section 2 BACKGROUND

The Northern Canada Power Commission (NCPC), the predecessor corporation to NWTPC, was a federally funded utility under the regulatory supervision of the Parliament of Canada. NCPC was not required to perform regular cost of service studies, with the result that the rates charged by NCPC did not reflect its costs of providing electric service to communities in the Northwest Territories (NWT). The rates of NCPC were allowed to evolve over time without the benefit of adequate cost information or a consistent set of rate principles. These rates and the lack of information with respect to the costs of providing service were inherited by NWTPC.

On April 5, 1990, the Board was directed to conduct a public review into NWT electrical rate structures and provide a written report to the Executive Council. The Board's report, submitted to the Executive Council on October 29, 1990, made two recommendations. The first was that legislative changes should be made to give the Board the power to fix the rates of NWTPC. The Northwest Territories Power Coloration Act (NWTPC Act) was amended to reflect this recommendation, effective April 1, 1992. The second recommendation was that subsidies should be separated from the rate structure.

NWTPC, in anticipation of the fact that its rates will be set by the Board after April 1, 1992, submitted a proposed cost of service methodology to the Board on April 22, 1991 (Exhibit 3). NWTPC was interested in obtaining comments and suggestions from the Board and interested parties on its proposed methodology prior to undertaking its initial cost of service study in the winter of 1991-92. The Board will require that a cost of service study be filed to facilitate its assessment and setting of NWTPC's rates.

Section 3 CONDUCT OF THE REVIEW

The review process began on April 22, 1991 with the receipt of NWTPC's submission to the Board. The Board issued information requests to NWTPC which were responded to on May 31, 1991 and June 14, 1991 (Exhibit 4). The Board information requests were necessary to enable the Board to determine the appropriate scope of this review and ensure that the objectives of NWTPC in submitting its proposed methodology were fully understood by the Board.

The Board retained a rate design consultant to review and comment on NWTPC's April submission and to assist the Board in evaluating the comments received from other interested parties. The consultant filed his direct evidence with respect to NWTPC's proposed methodology on August 23, 1991 (Exhibit 15).

The Board held a public hearing in Yellowknife on October 29-30, 1991. Representatives from Centra Power Inc., Northland Utilities (NWT) Limited, Nerco Con Mine Limited, Royal Oak Mines Inc., the City of Yellowknife, the Village of Norman Wells and the GNWT as represented by the Department of Energy, Mines and Petroleum Resources were in attendance. Testimony was received from witnesses for NWTPC, Centra Power, Nerco Con Mine, the Village of Norman Wells and the Board's consultant. All parties were provided with an opportunity to question these witnesses. The process proved very useful in providing feedback and comments to NWTPC on its proposed methodology.

The position of NWTPC on various cost of service issues evolved considerably from the time of its April submission to its concluding oral argument at the hearing. The evolution resulted primarily from the quality of the suggestions put forth by the intervening parties and the willingness of NWTPC to incorporate the ideas of others into their methodology.

Section 4 PURPOSE OF A COST OF SERVICE STUDY

The process for determining the rates which a utility will charge for providing electrical service to its customers generally is divided into two phases. Phase I consists of determining the utility's revenue requirement or the total revenue which is allowed to be collected from its customers in a year. Phase II involves the determination of the utility's cost to serve each of its customer groups and the design of rates to collect those costs attributed to each group.

The determination by the utility of its costs to provide service to its customer groups is achieved through a cost of service study. Such a study usually proceeds in three steps:

1. Functionalization

   Functionalization refers to the splitting of capital assets and operating expenses into groupings which represent the specific function to be performed. The functions usually used are production (generation), transmission, distribution and general or common. These functions comprise the major tasks which a utility must perform to provide electric service.

2. Classification

   Classification divides the costs associated with each function into components which bear a relationship to a measurable cost-defining characteristic of the services which a utility renders. The principle causes of investment and expense are the customer's demand requirements, their energy use and the number of customers which the utility serves. The classification components most commonly used are demand, energy and customer.

3. Allocation

Allocation is undertaken to distribute the demand, energy and customer costs associated with each function to the utility's customer classes. Allocations are made on the basis of various demand, energy and customer allocation factors. The customer classes most commonly used are Residential, Commercial, Industrial, Wholesale and Street Lights.

At the conclusion of the allocation process, the utility has a measure of the costs which it incurs to provide service to each of its customer groups. Cost of service information is the starting point in the design of fair and equitable rates. It is not the only criterion used in the design of rates, however, it is generally accepted that rates should reflect costs.

A more complete discussion of cost of service studies and the design of rates is found in Appendix B.

Section 5 COST OF SERVICE INFORMATION REQUIREMENTS

The development of useful and reliable cost of service information depends heavily on the availability and quality of the data upon which the cost of service study is to be performed. A lack of appropriate data may lead to inappropriate functionalization and preclude the use of certain classification or allocation procedures that would otherwise be more suitable in a given context.

Specifically, a utility requires financial, accounting and engineering data to perform a cost of service study.

Functionalization of capital assets and operating expenses can be performed reliably only if the recording of assets and the accumulation of expense data is done by major function or if sufficient detail is provided in the accounting records to permit functionalization to be from the records.

Data such as the number of customers, the kilowatthour (kW.h) sales and the kilowatt (kW) demands are required to develop the factors by which fictionalized costs are classified and allocated to the various customer groups.

NWTPC is cognizant of the deficiencies which exist in its accounting systems with respect to the provision of cost of service information. The April submission (Exhibit 3) details some of the problems in the financial and accounting records of NWTPC:

- inconsistencies exist between recorded plant and plant physically held by the Corporation.

expenses are accumulated by various cost centres rather than by major function.

a standardized method of allocating overhead to utility services, rate zones and plants needs to be developed.

NWTPC states, on page 4-2 of its April submission (Exhibit 3), that many alternatives for functionalizing, classifying and allocating expenses were not considered due to the lack of required information.

The Board is of the opinion that a lack of data should not act as a permanent constraint in the selection of appropriate cost of service procedures. If a more suitable approach is not used because of insufficient data, a plan should be implemented for collection of the necessary data.

Discussion in the hearing with respect to NWTPC's data requirements dealt with the need to change NWTPC's accounting systems to permit collection of the information necessary to perform adequate cost of service studies. Witnesses for NWTPC explained that its systems were largely inherited from NCPC and were acceptable in enabling NWTPC to meet its financial accounting requirements. The systems were not designed for the collection and provision of cost of service information. Witnesses asserted that the present systems are not sufficiently adaptable to meet regulatory requirements.

NWTPC states in its Direct Evidence (Exhibit 7) on page 27 that it views the selection of an appropriate system of accounts as only one integral component of satisfying its overall need to provide information for regulatory, statutory, operational and management purposes.

NWTPC witnesses explained that the Corporation's plan was first to review overall information requirements and then to decide on the implementation of a system of accounts as simply one component in the redesign of its entire management information system.

An alternative approach suggested by some parties was for NWTPC to proceed immediately with the implementation of a revised system of accounts. To do so would enable NWTPC to begin collecting requisite cost of service data in an appropriate manner. The overhaul of the "non-regulatory" accounting systems could then proceed as suggested by NWTPC, with new management accounting systems being designed to permit complete integration with the revised system of accounts.

If the implementation of a new system of accounts is postponed until the other changes can be made, a number of years will pass before a revised system of accounts is in place. The Board is of the view that the adoption of a revised system of accounts can and should proceed prior to the redesign of the other systems.

The Board recommends that a standard system of accounts for regulated utilities be adopted. Literature and computer software in the field of cost of service methods is generally written in the context of a standard system of accounts. It is suggested that NWTPC discuss with other utilities, currently using a standard system of accounts, the possibility of acquiring commercial or generally available computer software to meet its needs.

Section 6 PLANT ACCOUNTING ISSUES

Discussion took place in the hearing regarding the deficiencies which exist in NWTPC's accounting for plant. NWTPC states on pages 30-31 of its Direct Evidence (Exhibit 7) that its system of accounting for plant was inherited from NCPC with the ongoing result that assets are not being properly functionalized as production (generation), transmission and distribution. Specifically, some assets exist which have not been recorded and certain assets which were previously recorded may no longer exist. In addition, some assets have apparently been lumped together when recorded.

The problems faced by NWTPC regarding plant additions will continue until a revised plant accounting system is introduced.

The Board recognises that improvements in NWTPC's existing plant accounting information will not result from the introduction of a revised system of accounts. NWTPC is considering the initiation of a three year project to have all its plant audited and functionalized. Page 10-27 of NWTPC's April submission (Exhibit 3) provides an estimated cost for this project of $500,000. It is the Board's understanding that the successful completion of such a project would rectify the problems in NWTPC's fixed asset listing with respect to the recording of assets which may or may not exist and ensure that the assets which do exist have been properly functionalized. NWTPC witnesses stated that a $20,000 pilot project has been embarked upon in Fort Smith.

The Board is extremely concerned over the timing and appropriateness of the $500,000 expenditure in light of NWTPC's other priorities. The Board recommends that NWTPC use a best-guess approach in its asset valuation audit. NWTPC can determine a standard cost for a typical small plant using engineering evaluations. This standard cost would provide a breakdown between production (generation), transmission, distribution and general and common costs that NWTPC could use in its functionalization of its fixed assets.

Section 7 FUNCTIONALIZATION ISSUES

The major functions utilized by NWTPC were generally acceptable to all participants in the hearing. The Board is satisfied with NWTPC's continued use of Production (Generation), Transmission, Distribution and General and Common Administration.

The Board anticipates that NWTPC is functionalizing costs appropriately where direct assignment is possible. Costs and expenses associated with other utility systems should be collected and separated from electric costs through proper functionalization procedures. Costs which are not common such as capital expenses should not be included in common costs to be allocated later. Such costs and expenses should be treated appropriately at the fictionalization stage of the cost of service study.

Section 8 CLASSIFICATION ISSUES

Classification issues will be discussed by major function (i.e., generation, transmission, distribution and general and common), the manner in which NWTPC organized its material and in which the issues were discussed in the hearing.

Generation

The initial proposal of NWTPC in its April submission (Exhibit 3) was to classify its generation plant based on system load factor to reflect the fact that generation fixed costs have an energy component. NWTPC refined its proposal on page 35 of its Direct Evidence (Exhibit 7). Generation fixed costs are to be classified as 100% demand as NWTPC cannot ascertain the cost-causation behind its generation facilities at this time. The energy component in generation costs will be recognized in the allocation phase of the cost of service study.

Participants in the hearing were generally supportive of the 100% demand classification approach given the information available to NWTPC at this time. Some suggestions were made to NWTPC to distinguish between its hydro and diesel facilities. All participants concurred with the classification of diesel facilities as 100% demand. NWTPC was urged to conduct a study of the cost-causation behind its hydro generation facilities to allow for an appropriate energy classification of these facilities at a future General Rate Application (GRA). The Board concurs with the comments received in the hearing and is of the opinion that NWTPC's approach is reasonable for the near future.

The Board anticipates that NWTPC will be in a position at a future GRA to support its classification of its generation facilities on the basis of cost-causation.

Transmission

NWTPC proposed on page 36 of its Direct Evidence (Exhibit 7) to classify transmission plant as demand as it is typically designed and operated to meet system peak requirements. None of the participants were opposed to this proposal.

The Board anticipates that NWTPC will be in a position at a future GRA to support its classification of its transmission facilities on the basis of cost-causation.

Distribution

NWTPC's proposal in its April submission (Exhibit 3) with respect to its distribution facilities was to classify substation equipment as demand related and classify lines, transformers, poles and conductors 50% to demand and 50'% to customer due to a lack of information upon which to make a more precise estimate. NWTPC proposed in its Direct Evidence (Exhibit 7) that the classification of poles, conductors and transformers be split between demand and customer components based on a zero intercept method. NWTPC's proposals were generally acceptable to the participants. Proposals were made that investment in poles, services and meters could be classified as 100% customer.

The Board anticipates that NWTPC will be in a position at a future GRA to support its classification of distribution investment.

General and Common Costs

NWTPC's proposal with respect to general and common costs and administrative and general expenses was to use the labour ratios among the functions as a general approach to classifying these costs. Another suggestion put forth was to classify these costs in different ways based upon these costs having already been grouped by subfunction in the functionalization phase. A further suggestion was to classify General and Common expenses on the basis of total O&M net of fuel, lubrication and purchased power expenses and to classify Head Office and District Office expenses using a four-factor method.

The Board is satisfied with NWTPC's use of labour ratios at this time. If another method is more appropriate in a given circumstance, the Board anticipates that such information will be presented to it during the course of a future NWTPC GRA.

Section 9 ALLOCATION ISSUES

It is not possible to discuss the merits of the various allocation methods in isolation from the classification methods which received support in the previous section.

Most participants agreed that generation and transmission costs should be allocated using the coincident peaks (CP) of the classes instead of the non-coincident peaks (NCP) as NCP allocation methods do not recognize diversity of usage among the customer classes. NCP methods of allocation were recognized as appropriate for distribution as less diversity is present at the distribution level than at the generation and transmission level.

Generation

Discussion at the hearing regarding allocation was focused on the appropriate method by which to allocate production fixed assets. In conjunction with its proposal to classify all generation fixed costs to demand, NWTPC proposed on page 35 of its Direct Evidence (Exhibit 7) that generation fixed costs be allocated to the customer classes based upon the traditional average and excess demand methodology (traditional AED). The use of traditional AED recognizes energy usage in the assignment of generation costs. Most participants in the hearing concurred that the use of traditional AED was appropriate as NWTPC is currently limited to certain classification methods due to insufficient information on the cost-causative nature of their generation plant.

Considerable discussion took place with respect to the use of traditional AED as the method by which energy usage should be recognized in the assignment of generation plant. The principal criticism of the traditional AED method was that, while it recognizes energy in the formula, it is based upon non-coincident demands and does not properly allocate costs to off-peak and interruptible customers. NWTPC acknowledged this criticism but stated in its oral argument that interruptible and off-peak consumption was not a major issue with the Corporation in its current circumstances.

To enable the Board and interveners at future GRA's to compare the impact on various customer classes of the use of both CP and NCP allocation methods, the Board recommends that information be developed regarding the coincident peak demands of the customer classes on the system. The Board would also expect that should NWTPC begin to serve customers that are strictly off-peak or interruptible, that it would consider allocation methods such as Coincident Peak and Average or a modified form of AED that would properly reflect the contribution of these customers to system peak and system efficiency.

In the circumstances, the Board is satisfied with NWTPC's use of traditional AED in allocating generation fixed costs to the customer classes.

Transmission

NWTPC proposed on page 36 of its Direct Evidence (Exhibit 7) that transmission plant be classified as demand and allocated to the customer classes on the basis of their contribution to system peak. All participants in the hearing concurred with this proposal.

It appears at this time that allocation of transmission plant on the basis of customer contribution to system peak is appropriate and the Board is satisfied with NWTPC's use of this allocation method for transmission plant.

Distribution

NWTPC's suggestions with respect to the allocation of distribution facilities were put forth on page 36 of its Direct Evidence (Exhibit 7). Distribution substations were classified as demand and allocated based on non-coincident peaks. The demand component of poles, conductors and transformers as determined by a zero intercept analysis in the classification phase should also be allocated on the basis of non-coincident peak. The customer component of distribution poles, conductors and transformers was to be allocated based on the actual number of customers. Meters and services were to be allocated based on weighted customers.

Suggestions were made that in the short-term NWTPC might use other methods of allocating distribution plant due to the lack of information presently available to it. The Board expects that NWTPC will develop estimates of the class non-coincident peaks and have sufficient data at hand to perform zero-intercept analysis to enable it to conduct the allocation phase of its cost of service study as proposed.

The Board anticipates that NWTPC will be in a position at a future GRA to support its allocation of distribution facilities based upon its estimates of the class non-coincident peaks.

General and Common Costs

NWTPC proposed that labour ratios within a particular function be used to allocate general and common costs and administrative and general expenses, a position supported by some participants as being administratively simple and not apt to over-allocate expenses to hydro facilities. A four-factor method was suggested instead of labour ratios to correct for the fact that much of the costs accumulated under Head Office and general and common categories are attributable to plant investment, number of employees, number of customers and expenses, excluding fuel, lubrication and purchased power. Most hearing participants took issue with the use of plant investment as an allocation factor as administration and general expenses tend to be greater for diesel facilities yet a larger proportion would be attributed to hydro since it is the more expensive plant.

At this time, the Board is satisfied with NWTPC's use of labour ratios to allocate general and common costs and administrative and general expenses to the customer classes. If another method of allocating such costs is more appropriate in a given circumstance, the Board anticipates that evidence will be presented to it during the course of a future NWTPC General Rate Application.

Section 10 RECOMMENDATIONS

In this section the Board addresses issues which are related to NWTPC's cost of service study and the eventual development of electric rates in the NWT on a basis which reflects costs. The suggestions and recommendations contained in this section should be considered in conjunction with the specific recommendations provided by the Board in previous sections of the report.

NWTPC's information systems are presently designed to collect data at an administrative level and not at a plant-by-plant or community level. The availability of accounting and operational data at the plant level is necessary to determine the cost to NWTPC of providing electric service in any particular community. At this time, NWTPC does not know its costs to provide service in each community even though the present rate structure provides for a separate rate for each customer class in each community. Discussion focussed on the need for NWTPC to develop plant-level information for internal planning purposes and to facilitate the design of rate zones. Witnesses for NWTPC acknowledged that this information could be developed if NWTPC were so directed.

The Board is of the opinion that plant-level costs are necessary for the determination of maintenance schedules, for capital planning and to enable NWTPC to target conservation efforts towards high-cost, high-usage customers.

The Board recommends that NWTPC begin to develop plant or community-level costs immediately.

The design of rate zones was not a central concern in this review, however, NWTPC and other hearing participants recognized that costs will be a determinant in the design and eventual implementation of rate zones in the NWT. The principal concern amongst participants was the extent to which NWTPC could proceed in developing a rate zone proposal when their initial cost of service study has not yet been submitted to the Board nor is reliable information available on the costs to provide service at the plant level. It is the opinion of the Board that the concensus among participants was that NWTPC should proceed with a rate zone proposal and submit this proposal to the Board in conjunction with its initial cost of service study. The cost of service study should be done to reflect NWTPC's rate zone proposal and a cost study should also be done on a plant-by-plant basis. The Board recognizes that a decision on rate zones in light of the information provided by NWTPC's inaugural cost of service study maybe viewed as preliminary. It is the opinion of the Board, however, that it is better to adopt a rate zone design now and fine-tune it later than it will be to delay a decision on rate zones for a few years while NWTPC refines its cost information.

During the course of the hearing, NWTPC received comments on its rate zone proposal as outlined in its response to Board Information Request Two (BR-2) (Exhibit 4). It is not the intention of the Board to comment on these matters in this report as this is beyond the terms of reference provided to the Board.

The Board does note, however, that the rate zone proposal NWTPC submitted in response to BR-2 (Exhibit 4) was designed on the basis of east/west geographical and source of generation criteria. This proposal met with general approval from hearing participants. The Board anticipates that it will receive evidence from NWTPC at a Phase II hearing in 1992 with respect to the criteria which should be considered in the design of rate zones and a rate zone proposal.

NWTPC listed on page 10-25 of its April submission (Exhibit 3) its priorities with respect to rate setting issues and further refined its priorities in its direct evidence and in the hearing. In its oral submission at the conclusion of the hearing, NWTPC stated that it was seeking the Board's advice with respect to the requirement and prioritization of its various proposed projects. It is the responsibility of the management of NWTPC to determine where to best utilize its financial and manpower resources. The Board will examine the prudency of NWTPC's decisions in the context of a GRA.

With respect to a load research program, load characteristics information is sufficient for NWTPC's purposes at this time and can be developed from feeder data and surveys of field staff to estimate local load patterns. The Board did not receive sufficient evidence in the hearing to persuade it that a statistical load research program is required and prudent at this time. It is the expectation of the Board that load characteristic data can be developed and incorporated into the cost of service study which NWTPC will submit to the Board in the Fall of 1992.

Section 11 IMPLEMENTATION

NWTPC, in its oral argument, stated that it had several objectives in encouraging the GNWT to request the Board to conduct this review. NWTPC was seeking comments on its proposed cost of service methodology and wished to establish priorities regarding refinements of its methodology in order to produce a cost of service study which would assist in its design of rates. It is the opinion of the Board that NWTPC has received useful and timely comments from hearing participants on its proposed methodology.

NWTPC's final objective was for the Board to review its timetable for events for moving towards the eventual implementation of new rate structures and rate design. Page 12 of NWTPC's Direct Evidence (Exhibit 7) contained a timetable of events by which NWTPC proposed to move towards implementation of new rate structures. Participants in the hearing generally accepted the timetable, but some reservations were expressed that it may be somewhat ambitious, given NWTPC's current financial and manpower resources.

The Board would like to provide some general comments with respect to this timetable and the eventual implementation of new rates in the NWT.

The Board does not have any difficulty with NWTPC's proposal to submit a Phase I Revenue Requirement by the end of January, 1992 to support an across-the-board rate increase. Should NWTPC choose to apply for an interim increase in its rates at the time of this Phase I filing, the Board would expect to be provided with evidence that an interim increase is necessary to ensure the financial viability of the Corporation. The Board cannot comment at this time on whether a Phase I hearing could be held by April 1, 1992. A Board Decision on NWTPC's revenue requirement would certainly not be rendered by

April 1, 1992. The Board could expedite a decision on an interim refundable rate increase upon receipt of an application should NWTPC provide sufficient evidence of its financial need.

It is the Boards opinion that the filing of a cost of service study by NWTPC and the determination of rate zones are interrelated issues and should be dealt within one hearing. Again, the Board cannot comment on when its Phase II Decision would be forthcoming as the rendering of a decision will depend in part upon when the Board receives NWTPC's Phase II filings.

The Board's primary concern with respect to both the Phase I and II proceedings is that NWTPC develop and file submissions which are complete and represent its considered positions on these matters. The Board will expect NWTPC to support its proposals.

The Board's final comments regarding the implementation of its recommendations contained in this report pertain to the "limited resources" of NWTPC. "Limited resources" was presented at various times in the written evidence and in the hearing by NWTPC as its rationale for not having initiated or completed certain projects. Witnesses for NWTPC stated that its customers could not afford the additional expense of NWTPC acquiring the additional resources required to begin addressing some of its long-standing problems. NWTPC's strategy appears to be one of slow, steady progress at a pace which the customer can afford. The Board has concerns that NWTPC is cognizant of the amount of work which it must complete to meet its statutory and regulatory requirements yet persists in operating with a level of resources which in its own estimation is inadequate to the job. The Board is of the opinion that it may be in the long-term interests of NWTPC's customers for it to acquire the resources which it needs to complete its projects in the next few years. An increase in the operating expenses of NWTPC in the near-term will result but may well return a long-term benefit to NWTPC's customers in the form of a fully-regulated. efficiently run utility with rates which reflect costs.

Section 12 SUMMARY OF RECOMMENDATIONS

The Board recommendations are that:

1. NWTPC adopt a standard system of accounts for regulated utilities;

2. NWTPC use a best-guess approach in its asset valuation audit;

3. NWTPC functionalize costs appropriately where direct assignment is possible;

4. NWTPC develop information regarding the coincident peak demands of the customer classes on the system;

5. NWTPC begin to develop plant or community-level cost information; and,

6. NWTPC develop load characteristics information from feeder data and surveys of field staff.

The following is a copy of the Terms of Reference provided to the Board in the Executive Council's directive of April 8, 1991.

Whereas the Executive Council may issue directives to the Public Utilities Board.

And whereas the Minister Responsible for the Public Utilities Board may direct the Board to inquire into a matter or to hold a hearing.

And whereas it is desirable to have the Public Utilities Board review the cost of service methodology of the Northwest Territories Power Corporation.

Therefore, pursuant to the provisions of the Public Utilities Act, the Executive Council and the Minister Responsible for the Public Utilities Board hereby direct the Public Utilities Board to review the Northwest Territories Power Corporations cost of service methodology in accordance with the following terms and conditions:

TERMS OF REFERENCE

To review the Northwest Territories Power Corporation's cost of service methodology.

PROCEDURES

The Public Utilities Board shall hold a hearing in Yellowknife.

The Board will conduct the public hearing in accordance with such procedures as it may set and as may be necessary to undertake the Terms of Reference in the most expeditious and proper manner.

REPORTING

The Board shall provide a written report to the Executive Council of the Government of the Northwest Territories by September 1, 1991. The report shall include an analysis of the Corporationts cost of service methodology. If the Board finds that changes are advisable, the report shall identify those changes needed to achieve an acceptable cost of service methodology.

Dated this 8th day of April, 1991 at the City of Yellowknife in the Northwest Territories.

Dennis Patterson
Chairman of the Executive Council

Minister Responsible for the Public Utilities Board

APPENDIX B

The material that follows is a detailed explanation of the conduct of a cost of service study.

ELECTRICAL UTILITY COSTS

The NWT, given its vast area, sparse population, and widely separated load centers, has developed an electrical system that is unique in North America. Many of the traditional means of lowering unit costs and increasing reliability, such as generation pooling, high voltage transmission grids, and designed redundancy in distribution systems are simply not feasible. The wide dispersion of load centers precludes economies of scale and the extreme winter temperatures and relatively short summer provide a relatively harsh operating environment. Limited development and utilization of hydro capacity has meant that most communities are served by isolated diesel generation. Fuel costs are extremely high, particularly in remote communities.

The cost standard is the most widely accepted measure against which utility rates are compared to determine the extent to which they are just, reasonable and not unduly discriminatory.

It is, however, widely recognized that the costs of providing service are not reflected in the rates of the Northwest Territories Power Corporation. For this reason the Board was directed to review the cost of service procedures of the Corporation as a step toward the gradual implementation of cost-based rates.

The discussion that follows is intended to provide a background for understanding electric utility costs and the concepts and principles utilized in a cost-of-service study to assign responsibility for costs to the various classes of consumers. A glossary of terms is provided in Appendix C.

General Nature of Costs

Electric utility operations include the functions of production (generation), transmission, and distribution of electricity to different consumers. A large proportion of utility costs occurs as a result of investment in relatively long-lived facilities, such as power plants, poles, wire, transformers and meters, to carry out the various functions.

Power production or generation costs include fuel costs, purchased power expenses, operation and maintenance expenses, and the relatively fixed costs associated with investment in generating facilities, including depreciation, taxes, and either return on investment for investor-owned utilities or debt service requirements plus margin for publicly owned utilities.

Energy requirements, measured by the total kilowatthours generated and purchased, are the principal determinant of the utility's fuel cost and the energy portion of purchased power costs.

The rate of consumption during a given time interval is referred to as the demand and is measured in kilowatts. Since the use of electricity varies from hour to hour and from day to day throughout the year, and because electricity cannot be generated at times of low demand and stored for use at times of high demand, the time patterns of the loads on an electric system are important determinants of costs. Generating plant sufficient to meet peak demands, plus an appropriate operating reserve margin, must be provided by the utility. Demands of customers also determine to some extent the amount of transmission and distribution plant that the utility must provide.

Transmission costs include all costs associated with the facilities provided to carry electricity from the point of generation to the distribution system. Because the transmission system must have sufficient capacity to meet peak demands, transmission costs are related primarily to demand.

Distribution costs are those costs associated with delivering electricity from the high-voltage transmission system to the individual customer. As previously noted, some distribution investment is related to demand, but the number of customers served is also an important determinant of the amount of distribution investment by the utility. Customers such as large industrial firms, that take service directly from transmission lines, do not require low-voltage distribution systems. On the other hand, residential and many commercial/industrial customers can be served only through an extensive distribution system that provides electricity at the relatively low utilization voltages of these customers. Thus, each customer elms imposes different costs upon the utility. Customer billing and administrative and general costs are a relatively small proportion of total utility costs, but are a significant element in the cost of service to the residential and small commercial classes that are relatively small-use customers.

Cost Effects of Changes in Load Patterns

As previously noted, the usage or load patterns of a utility's customers are important determinants of costs. Since load patterns change by time of day and by season, the costs of providing electric service also vary by time of use. A utility's load pattern is a composite of the load patterns of the individual customers served. Every individual customer's load pattern is different; but the utility will experience peak demands caused by the aggregation of customer demands resulting from such factors as climate, cultural influences, and the specific characteristics of electrical appliances and equipment.

If a utility's load pattern can be flattened by reducing customer usage during the peak periods, potentially significant cost benefits may be realized. Capacity carrying costs per kilowatthour will tend to decrease as load patterns are leveled; on the other hand, they will tend to increase if peaks are increased and load factor deteriorates. Fuel costs tend to rise as load increases and peaks become more accentuated, and they tend to decline as load curves are flattened. Purchased power costs may rise with decreases in system load factor and decrease as load factor increases, reflecting the fact that purchased power costs are a function of the capital and fuel costs incurred by the supplier.

Transmission costs per kilowatthour are affected by demand in a manner similar to generation costs, as described above, but are also affected by reliability criteria, distance from the generator, and other factors, not just by peak demands.

Distribution costs are not significantly affected by changes in system load patterns. There may be some effects on demand-related costs, such as line transformers, if customer maximum demands are changed.

Customer accounting and administrative and general costs are generally considered to be independent of changes in customer usage and thus would not be altered by changes in load patterns. However, since such costs are relatively fixed, the cost on a per-unit basis will change as kilowatthour consumption varies upward or downward.

Cost of Service Principles

The foregoing discussion has described electric utility costs in general terms. In order to provide a basis for designing rates for pricing service to the various customer groups, costs must be allocated and assigned among customer groups, in what is known as a cost of service study. The following discussion is intended to briefly examine the theoretical and practical considerations underlying the various cost study methodologies currently in use. It is basic to the understanding of both accounting and marginal costing methodologies, but is presented in terms of the accounting or fully allocated cost-of-service study, since that is the type of study that has historically been presented by utilities whose rates are fixed by the Board.

A fully allocated cost-of-service study assigns plant, property, and operating expenses to each customer class, measuring costs of rendering service to the classes of customers under study and assessing each classification's contribution to rate of return. It should be understood that a cost-of-service study is not a precise measurement of accounting costs, but an approximation of cost responsibility by class of customer. A cost-of-service study does not establish the value of service to the customers or directly determine the structure of rates, although it does provide useful cost information for rate design.

For a typical utility the cost-of-service or revenue requirement is comprised of operating and maintenance expenses, depreciation expense, taxes other than income taxes, income taxes (if applicable), and a return on investment. When accounting or embedded costs are fully distributed or allocated among all rate classes based on customer, demand (kilowatt or kW), and energy (kilowatthour or kWh) class consumption characteristics, the resulting cost distribution is referred to as a fully allocated cost-of-service study. The utility's total costs have been allocated in their entirety, or fully allocated, to the utility's customer classes. The fully allocated cost-of-service study continues to play a major role in contemporary rate design. The use of fully allocated class costs to evaluate existing and proposed rate design is consistent with the principle that rates should reflect the cost to serve the various customer classes.

The fully allocated cost-of-service study is a process based on utility accounting records that separates costs into categories. Cost categorization proceeds from functionalization to classification and then to the allocation of costs. Functionalization resigns costs by type of related electric plant, while classification of costs categorizes costs by demand-, energy- and customer-related components. Classified costs are then allocated to customer classes based on selected usage characteristics.

Fully allocated costing methodologies begin with the utility's total revenue requirement which is separated (functionalized) into production (generation), transmission, distribution, and administrative and general functions using an acceptable system of accounts. The functionalized plant is then classified according to the basic cost components: demand-, energy- and customer-related costs. Customer class cost responsibility is determined by three components: the class contribution to the system capacity or demand requirements; the relative amount of energy consumed (kWh); and electric system access costs imposed by the class, regardless of consumption. Class revenue requirements, when determined by a fully allocated cost study, preserve equitable relationships based on known costs according to acceptable allocation methods. An analysis of relative measures such as class contributions to return on rate base or revenue to cost ratios identifies classes that are subsidized and classes providing subsidies to others.

Cost Functionalization and Classification

Rate base (primarily plant) and operating expenses are grouped (functionalized) into functional cost classifications such as production (generation), transmission, and distribution, based on the utility's books and records. Rate base and operating expenses are then examined to determine if assignment to a specific class of service or customer is possible.

If specific assignment is not possible, the plant and operating accounts are classified in terms of customer use characteristics, such as demand or energy use, and number of customers, and are then allocated to customer classes.

a. Demand-Related

The costs classified as demand-related are those determined to vary or occur in proportion to or resulting from the kilowatts of demand which the customers impose on the system. Demand-related costs can be considered in at least two subcategories; system peak demand related (coincidental), and customer maximum demand related (noncoincidental). Also, a portion of base load unit capacity costs may in some instances be considered related to average demands (energy). It is important for the analyst to understand the distinction between fixed costs and demand-related costs before attempting any cost classifications since these terms are not synonymous.

Generally, production and transmission demand-related costs are considered to be related to coincidental demands, since sufficient capacity must be provided to meet the demands of all customers at one time, the coincidental system peak. In contrast, line transformers and other distribution system components are sized to meet the maximum demands of customers regardless of time of occurrence. For this reason, distribution demand-related costs are usually allocated on the basis of non-coincident demands.

b. Energy-Related

Energy-related costs are those determined to vary in proportion to the kilowatthours consumed by the customer. The principal costs in this category are fuel burned, variable maintenance, and portions of purchased power expenses. Base load capacity costs may also be considered as partially energy-related in certain circumstances.

c. Customer-Related

Costs assigned to this category are those which tend tovaryin proportion to the number of customers served. At least two subcategories are generally considered; average number of eustomer-related, and weighted customer-related. The latter category, weighted customers, is utilized when the primary cost causation is number of customers, but where it would be incorrect to assume all types of customers are to be equally counted. An example is commonly found in the consideration of meter investment. Each customer has a meter, but large commercial and industrial meters, for instance, generally cost much more than residential and small commercial meters. Employment of appropriate weighting, in this case weighting the large and industrial customers more heavily, corrects for the cost differential between types of meters.

Costs assigned to the customer-related category usually include a portion of the distribution system required to supply a minimum or nominal load of a customer, as well as metering costs and customer accounting costs. There are two generally accepted methods for classifying distribution facilities, such as lines and transformers, that are considered to have both a demand and a customer component. These are the “zero intercept” and the “minimum size” methods. The use of one or both of these methods is usually heavily influenced by the available data.

The general cost classifications of functionalized plant are shown in the following table:

Plant Item (Functionalized)	Cost Classifications
Production (Generation)	Demand/Energy
Transmission	
Substations	Demand
Lines	Demand
Distribution	
Substations	Demand
Lines	Demand/Customer
Transformers	Demand/Customer
Services	Customer
Meters	Customer
Street Lighting	Specific
General and Intangible	As Determinable/Pro Rata

Upon completion of the classification process to demand, energy or customer, costs are spread to the classes of service based upon appropriate allocation factors.

Methods for Allocating Demand-Related Costs

There are a number of methods available for allocating capacity or demand-related costs at the production/transmission level. Since some thirty different methods are discussed in industry literature, it is obvious that there is a wide diversity of opinion.

Although many methods have been developed, most embody concepts that are found in the following three categories:

(1) Coincident peak methods
(2) Noncoincident peak methods
(3) Average and excess demand methods

Coincident peak methods allocate demand costs to the various classes in proportion to the contribution of each class to system peak demands. In the simplest form, sometimes referred to as the CP method, the allocation is based only on class demands at the time of the annual system peak demand, which might be summer or winter. In the case of utilities with seasonal peaks that are nearly equal, an average of winter and summer might be used. On some systems an average of the 12 monthly peaks (12-CP method) might be justified, particularly where no strong seasonal peaking pattern is exhibited. The coincident peak methods are founded on the concept that systems are planned to serve the coincident peaks of all customers at the same time. The principal objections to the use of the CP method are that off-peak loads are allocated zero demand responsibility and that cost responsibilities may change radically if peaks are not stable. The use of multiple peak responsibility approaches, such as the 12-CP, is designed to overcome these objections.

Noncoincident peak (or NCP) methods utilize class maximum demands as the basis for allocation, regardless of how these demands coincide with the system peak or with the peak demands of other classes. The effect is to treat classes as if they are served independently, which is not the way that systems are planned or operated. While the NCP or Sum of the Class Peaks Method does recognize class load factor to some extent, it assigns the benefits of interclass diversity in an irrational manner; it is often stated that even a customer with a 100-percent load factor shares in the benefits of diversity under this procedure. One of the strongest criticisms of methods involving noncoincident demands is their direct conflict with modern concepts of time-of-use costing and pricing.

The Average and Excess Demand (AED) method was developed many years ago as a way of overcoming objections to the CP and NCP methods and of recognizing criteria such as load factor and diversity. In its traditional form, which uses noncoincident demands, the AED method uses two components to allocate the system peak demand among classes. The average component is determined by dividing the system and class energy responsibility (sales plus losses) by 8,760 hours. The system excess demand, the difference between the system peak demand and the system average demand, is allocated among classes in proportion to the sum of the excess demands of the classes. The excess demand for each class is determined as the difference between the class maximum noncoincident demand and the class average demand. For each class, the sum of its average demand and its allocated share of the system excess demand yields the class average and excess demand (AED); the sum of the class AED's will equal the system peak demand. The method recognizes diversity, which decreases with increasing load factor and thereby assigns less of the diversity benefits to high load factor customers. A problem with the AED method is that it does not consider the time element of the system load since it utilizes noncoincident demands and cannot distinguish between on-peak and off-peak loads with the same load factor. The problem can be alleviated to some extent by the use of coincident demand data.

A lesser known version of the AED method, sometimes known as the Average and System Peak Excess method, uses class demands that are coincident with the system peak in determining class excess demands to allocate the system excess demand. To avoid the same allocation to an off-peak class as would result from pure coincident peak responsibility, a class with an average demand greater than its system peak contribution is allocated zero excess demand. Thus, the system excess component is allocated only to classes that have a positive contribution to the system peak over and above their average demand. Critics point out that where there is no off-peak class the method is equivalent to the CP method. The primary criticism of the CP method is that it fails to deal adequately with an off-peak class as no costs are allocated if the class has zero load at the time of the system peak. The Average and System Peak Excess formula does allocate costs to the off-peak class even if the class has zero load at the time of the system peak.

The **AED** formulas are subject to the criticism that they give too much weight to energy in the form of average demand, which is simply energy divided by a constant. The traditional form, using noncoincident demands has also been criticized as being outdated, since it was developed at a time when load research data was relatively unavailable. Its simplistic assumption that there is a linear relationship between load factor and coincidence factor is known generally to be erroneous.

An allocation method which does not use the excess demand concept is Coincident Peak and Average. In this method, the average demand of each class is added to the class demand at the time of the system peak. The sum of the class peak and average demands thus determined is the allocation factor. This formula is relatively simple yet limits the weighting given to energy (average demand) in the allocation of demand-related costs.

In order to provide an illustration of the effects of the demand allocation formulas or . methods previously described, an illustration is provided on the following pages. The assumed basic system data include five hypothetical classes spanning a range of load factors and peaking characteristics.

ILLUSTRATION OF DEMAND ALLOCATION FORMULAS

Basic Data

	Annual kWh	System Peak, kW	as Peak, kW	Average Demand, kW (kWh/ 8760 hours)	Load Factor
Residential	4,662,664	1,248	1,300	632	40.94%
Commercial/Indust	4,087,416	660	880	467	53.02%
Industrial	490,560	72	80	56	70.00%
Street Lights	80,000	20	20	9	45.66%
Summer Seasonal	315,360	0	80	36	45.00?/.
	9,636,000	2,000	2,360	1,100	65.00%

Note that the system excess demand is the amount by which the peak demand, 2000 kW, exceeds the average demand, 1100 kW, which is 900 kW.

Coincident Peak Method (CP)

	system Peak, kW	Percent Responsi-bility
Residential	1,248	62.40%
Commercial/Indust	660	33.00%
Industrial	72	3.60%
Street Lights	20	1.00%
Summer Seasonal	o	0.00%
	2,000	100.00%

Non-Coincident Peak Method (NCP)

	Class Peak, kW	Percent Responsi-bility
Residential	1,300	55.08%
Commercial/Indust	880	37.297.
Industrial	80	3.39%
street Lights	20	0.85%
Summer Seasonal	80	3.39%
	2,360	1 00.00%

Coincident Peak and Average Method

	system Peak, kW	Average Demand, kW	Coincident Peak and Average Demand, kW	Percent Responsi-bility
Residential	1,248	532	1,780	57.42%
Commercial/Indust	660	467	1,127	36.35'/0
Industrial	72	56	128	4.1 3%
Street Lights	20	9	29	0.94%
Summer Seasonal	o	36	36	1. 160/0
	2,000	1,100	3,100	1 00.00%

Traditional Average and Excess Demand Method (AED)

	Average Demand, kW	class Peak, kW	Class Excess Demand, kW	cated System Excess Demand, kW (Note A)	Average and Excess Demand, kW (AED)	Percent spo bility
Residential	532	1,300	768	549	1,081	54.05%
Commercial/Indust	467	880	413	295	762	38. 10%
Industrial	56	80	24	17	73	3.65%
Street Lights	9	20	11	8	17	0.85%
Summer Seasonal	36	80	44	31	67	3.36%
	1,100	2,360	1,260	900	2,000	1 00.00%

(A) Allocated in proportion to Class Exoass Demand column

Average and System Peak Excess Method

	Average Demand, kW	System Peak, kW	class Excess Demand, kW	Allocated System Excess Demand, kW (Note A)	Average and Excess Demand, kW (AED)	erce spo bility
Residential	532	1,24a	716	688	1,220	61.00%
Commercial/Indust	467	660	193	186	653	3266%
Industrial	56	72	16	15	71	3.56%
Street Lights	9	20	11	11	20	1.00%
Summer seasonal	36	0	0 (B)	o	36	1.80%
	1,100	2,000	936	900	2,000	100.00%

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(A) Allocated in proportion to Class Excess Demand column
(B) Exoasa is set at zero if average demand exceeds peak contribution

Summary of Percentage Responsibilities under Various Methods

	Coincident Peak Method	Non-Coincident Peak Method	Coincident Peak and Average Method	Traditional Average and Excess Demand Method	Average and system Peak Excess Method
Residential	62.400/.	56.08%	57.42%	54.05%	61 .00%
Commercial/Indust	33.00%	37.29%	36.35%	36.10%	32.65%
Industrial	3.60%	3.39% (2)	4.13%	3.65% (2)	3.55%
Street tights	1 .00%	0.65%	0.94%	0.65%	1 .00%
Summer Seasonal	0.00% (1)	3.39% (2)	1.16% (3)	3.35% (2)	1.80% (3)
	1 00.00%	1 00.00%	100.00%	1 00.00%	100 .00%

Observations

1. Nota that the Summer Seasonal load, on this assumed winter-peaking system, receives a zero allocation of demand responsibility under the CP method.

2. Note that the Industrial and Summer seasonal loads, equal in size but with widely differing impacts on the system peak, receive the same or nearly the same cost responsibility under both the NCP and the traditional AED methods.

3. Nota that the Coincident Peak and Average method and the Average and System Peak Excess method both allocate some cost responsibility to the Summer seasonal load, but much less than is accorded the Industrial load.

APPENDIX C

GLOSSARY OF TERMS

ALLOCATION The apportionment of the total cost of service between appropriate classes of service. Often used in the narrow sense of allocating common or joint use costs by means of an allocation factor as opposed to the direct assignment of specific identifiable costs.

BASE LOAD GENERATION Generating facilities within a system which are operated at or near full capacity for long periods of time to maximize system efficiency and minimize system operating costs. They serve all or a part of the minimum system load over a period of time, called the base load, and are usually the most expensive units in terms of capital investment.

CAPACITY FACTOR The ratio of the average load on a generator for the period of time considered to the capacity rating of the generator. Sometimes referred to as plant factor.

CLASSIFICATION (COST) **The** division of costs into principal categories, each bearing a relationship to a measurable cost-defining characteristic of the service rendered. Examples would be demand-related, energy-related and customer-related.

COINCIDENCE FACTOR The ratio of the coincident maximum demand of two or more loads to the sum of their noncoincident maximum demands for a given period. It is the reciprocal of the diversity factor and is always less than or equal to one.

COST OF SERVICE The total amount of money required to provide a utility service, including expenses, taxes and return on the investment. For ratesetting purposes the cost of service may be thought of as an annual revenue requirement.

COST OF SERVICE STUDY An analytical process wherein the utility cost of service is functionalized, classified, and allocated or assigned to the various customer classes provided service.

DEMAND (ELECTRIC) The rate at which electric energy is delivered, usually expressed in kilowatts or other suitable unit.

AVERAGE The demand determined by dividing the total number of kilowatthours in an interval of time by the number of time units in the interval.

COINCIDENT The sum of two or more demands which occur in the same time interval.

INSTANTANEOUS PEAK The maximum demand at the instant of greatest load.

INTEGRATED The demand measured over a demand interval of time, usually 15 minutes, 30 minutes, or an hour. It is the summation of the continually varying instantaneous demands over the specified demand interval.

MAXIMUM The greatest of all demands of the load under consideration which has occurred during a specified period of time.

NONCOINCIDENT The sum of two or more individual demands which do not occur in the same demand interval. Meaningful only when considering demands in a limited period of time, such as a day, a week, a month or a season, usually for not more than a year.

DIVERSITY That characteristic of electric loads whereby individual maximum demands usually occur at different times. Diversity may be measured between the appliances or electrical devices that make up an individual customer's load, between customers in a class (intraclass diversity), and between classes (inter-class diversity). Diversity among customers' loads results in diversity among the loads of distribution transformers, feeders and substations, as well as between entire systems.

DIVERSITY FACTOR The ratio of the sum of the noncoincident demands of two or more loads to their coincident maximum demand for the same period. The diversity factor is the reciprocal of the coincidence factor and is always greater than or equal to one.

FIXED COSTS Those costs that do not vary with the number of kilowatthours supplied. Examples would be the ownership costs associated with plant and other overhead costs.

FUNCTIONALIZATION The arrangement of costs according to major functions, such as production, transmission, distribution and general. While functionalized costs are usually available from a utility's books and records, cost of service analysis may result in finer groupings, such as separating subtransmission from transmission.

KILOWATT One kilowatt equals 1,000 watts, where the watt is an electrical unit of real power or rate of doing work. One kilowatt is equivalent to approximately 1.34 horsepower.

__KILOWATTHOUR__ **The** basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatthour equals 1,000 watthours.

__LOAD FACTOR__ The ratio of the average load supplied during a designated period of time to the peak or maximum load in that period. Load factor may be derived by dividing the number of kilowatthours in the period by the product of the maximum demand in kilowatts times the number of hours in the period.

__LOAD__ __RESEARCH__ **The** study and measurement of the characteristics of electric loads, usually in terms of class demands, both noncoincident and coincident with system peak demands.

__PEAKING GENERATION__ Generating equipment normally operated only during the hours of highest daily, weekly or seasonal loads, to meet a portion of the system load that is above the base load. Peaking units may be older, less efficient base load units or may be units not designed for continuous operation. While peaking units are the least costly in terms of capital investment, they have relatively high variable operating costs.

__VARIABLE COSTS__ Those costs, such as fuel costs and variable maintenance costs, that vary with the number of kilowatthours supplied.