AN APPLICATION OF MARGINAL COST PRICING PRINCIPLES TO B. C. HYDRO

by

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ABSTRACT

The purpose of this paper is to develop and apply a methodology to determine the marginal economic costs of supplying electricity in the predominantly hydro-electric system of the British Columbia Hydro and Power Authority (B.C. Hydro). This information is used to design an economically efficient rate structure in which marginal price is set equal to marginal economic cost. The resulting implications for the growth rate in electrical demand and costs are then calculated.

A computer simulation model is built which, once given a demand forecast to 1990, plans and operates the electric system in a cost minimizing fashion subject to technical constraints and the operating policies of B.C. Hydro. The associated annual accounting costs are determined and the rate levels adjusted in accordance with the Authority's financial policies.

Marginal economic costs are calculated by introducing various alterations to the demand forecast and examining the implications for the present value of economic costs of such changes. These amounts, when divided by the quantity of electricity involved, give estimates of the unit costs of a change in energy and/or peak demand for various classes of customers.

These marginal economic costs are then incorporated in a redesigned rate structure in which marginal prices equal these marginal costs while average prices continue to equal average accounting costs. By applying various estimates of long run own

price elasticity of demand, the impact on demand growth caused by marginal price changes can be determined. This new demand forecast will, in turn, affect system design and operation and thus ultimately, costs.

The result of this analysis is that the larger users (both within each class and within the system) face substantially higher marginal rates from those now in effect. In particular, the economic analysis attaches far greater weight to the energy component of demand in the energy-critical B.C. Hydro system than does the accounting approach. Under the median elasticity estimates, this rate structure reform reduces the electrical growth rate from 9.0 to 7.0 percent in the 1976-1990 period, reduces average real accounting costs from 18.1 to 16.5 mills per KWH, and reduces the gross debt outstanding in 1990 from 17.1 to 11.2 billion historic dollars.

We conclude that there exists substantial gains in social welfare to be obtained from redesigning B.C. Hydro's electrical rate structures.

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1. INTRODUCTION

In recent years, there has been growing public concern about the actions and policies of many North American electric utilities. Much of the criticism has centred around the high growth rates projected by these utilities and the means proposed to fulfil this forecast demand. Considerable attention has been paid to their rate structures with some critics holding them responsible for "excessive" growth rates.

Most electric utilities in North America long ago adopted a declining block rate structure. This meant that, both within and between classes of customers, the greater the consumption the lower the unit price of electricity. Although now usually less pronounced, this format remains predominant and is justified by the utilities as being "cost based".

The purpose of this paper will be to use economic analysis to suggest an appropriate rate structure for one particular utility, B.C. Hydro. Although the primary emphasis will be on developing and applying a methodology for determining and allocating economic costs, consideration will also be given to the implications that the resulting economically appropriate rate structures have for demand growth.

The primary criterion that will be employed in designing this rate structure is that of economic efficiency. This means that a necessary condition for the efficient allocation of resources and the maximization of social welfare is that the marginal price of a product must equal its marginal social cost of production. Much of this paper will focus on how best to determine the marginal costs associated with supplying electricity.

The selection of B.C. Hydro as the case study was influenced, naturally, by its geographic proximity. There were many reasons, however, which make it an ideal candidate for analysis. B.C. Hydro's forecast growth rate for electricity is one of the highest on the continent, and its expansion plans are running into increasing opposition throughout the province. An independent analysis of the appropriateness of its rate structure could help to clarify some the issues being discussed.

Secondly, the very nature of the B.C. Hydro system, with its existing and growing heavy reliance on hydro-electric generation sources, presented special opportunities. While this type of system is unusual in a world context, it is characteristic of several other important Canadian electric utilities. It has been suggested (falsely) that marginal cost analyses of predominantly hydro-electric systems are particularly difficult to perform. To the best of my knowledge, none has been done to date.[1]

Finally, the public availability of several recent extensive publications by B.C. Hydro has provided me with sufficient technical information to undertake this analysis. In addition, the ready co-operation, assistance and interest of many Hydro officials in a variety of areas contributed greatly to my understanding of the utility.

The next chapter contains a description of B.C. Hydro as it currently exists, including a review of the way in which it forecasts electrical demand, determines its expansion programme,

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[1] See, for example, Barnett(1977).

finances its growth and sets rates. The third chapter examines what economic theory suggests in the way of appropriate rate structures, assesses various methodologies that have been developed to allocate costs, and outlines the approach to be employed in this analysis. The following two chapters detail the model that is used and present the cost allocation results that it generates. The sixth chapter examines some of the implications and applications of these results - for the design of the rate structure, and for the forecasting of future demand. The concluding chapter briefly summarizes the main results of this paper and comments on the relevance and likelihood of acceptance of the underlying principles.

2. B.C. HYDRO TODAY

2.1 Introduction

British Columbia Hydro and Power Authority was created as a Crown corporation by the government of British Columbia in 1962. It was formed by the amalgamation of two electric utilities then serving different areas in B.C.: the privately-owned British Columbia Electric Company Limited and the Crown corporation British Columbia Power Commission. The original legislation was held to be invalid by the Supreme Court of British Columbia, but the union was formally cemented with the passage in 1964 of the British Columbia Hydro and Power Authority Act.

Under this Act, B.C. Hydro was given broad powers and has developed an extensive system of public utility services. At present it operates a regional gas distribution system, an inter- and intra- city bus passenger service, a small freight railway and three dams in connection with the Columbia River Treaty. By far its largest responsibilities, however, lie in the electric service area. B.C. Hydro is the third largest electric utility in Canada, serving an area containing more than 90 percent of the population of British Columbia.

The provincial government has never formally defined the basic mandate or formal objectives of B.C. Hydro. The Authority has itself recently stated that the typical function of a publicly owned utility might be summarized as follows:

> To supply the demands of its customers for energy at the lowest cost consistent with safety to its employees and public, good quality of service to its customers, and subject to the social, economic and environmental policies of the Government.
> (B.C. Hydro, 1975b, 12)

Final decision-making authority within B.C. Hydro is vested with a Board of Directors, currently consisting of five members including the provincial cabinet minister responsible for energy. The Authority has full power to determine the rates charged for its services. Only in the case of one railway line and of electricity and natural gas sold outside the province are these prices subject to external approval.[2] In the case of specific projects that B.C. Hydro seeks to undertake, approval may be required from the appropriate external authorities.

B.C. Hydro is subject to all federal taxes except taxes on income and capital. It generally pays the equivalent of the same local and provincial taxes as any other corporation, with the exception of a special school tax exemption on its biggest hydro-electric generating installations. Its bonds and other securities are unconditionally guaranteed by the Province of British Columbia.

As of March 31, 1976, B.C. Hydro's total assets stood at slightly over $4 billion. Of this, more than $3 billion was financed through bonds issued or acquired by the Authority. B.C. Hydro's revenues in the 1975-76 fiscal year slightly exceeded its expenses, but only after a special subsidy from the

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[2] The British Columbia Energy Commission is empowered to review certain discrimination complaints and the provincial government intends to establish a permanent Legislative Committee to examine the large Crown corporations.

provincial government to cover the loss associated with bus transit operations (see Appendix A).

2.2 Past And Present Policies Of The Electric Service

2.2.1 Demand for Electricity

Until recently, the electric service of B.C. Hydro has experienced relatively rapid growth in the demand for its product. At this stage it is important to distinguish clearly between the energy and peak demand components of this growth. The demand for electrical energy reflects the total energy requirements in a given time period (say one year) without regard to the rate of use of that energy within the specified time period. It is measured in kilowatt-hours. Peak demand, on the other hand, reflects the maximum rate of energy consumption in a given time period (usually one hour). It is measured in kilowatts. The two concepts are related through the load factor, a ratio of the average demand in kilowatts supplied during a designated period to the maximum demand occurring in that period. Throughout this paper the demand for electricity (or load demand) will be used in the general economic sense and refer to both components of electrical demand, while the energy or peak demand terminology will be used when referring specifically to either component.[3]

Since its formation in 1962, B.C. Hydro's sales of

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[3] This distinction is carefully made here because of the common usage of the term "demand" in the electrical literature to refer only to what I have called "peak demand".

electrical energy to the public have increased from 5.5 to 20.6 billion kilowatt hours, an average annual compounded growth rate of 9.8 percent. Over this same period, the peak one-hour demand has had an annual growth rate of 9.4 percent, expanding from 1.2 to 4.1 million kilowatts. Annual increases in electrical energy consumption exceeding ten percent took place in the 1965-1970 period and again in 1973 and 1974, with actual reductions occurring in 1975 and 1976.

At present, consumption of electrical energy is fairly evenly split among the three major customer classes: residential, general and bulk. The general class comprises all commercial customers plus the smaller industrial users, whereas the bulk class contains large industrial consumers. In the past,net energy sales to other electrical systems have usually represented less than 5 percent of total sales.[4]

During the 1962-1976 period, the share of the total B.C. energy market supplied by electricity rose slightly and now stands at close to 18 percent. Oil continues to supply just over half of the total provincial market, followed by natural gas with 20 percent and then electricity. B.C. Hydro's share of the electricity market has grown from less than half to its present 65 percent of the provincial total. Although supplying the vast majority of residential and commercial customers, the Authority does not provide exclusive service to a significant part of the large industrial market which has built substantial hydro-

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[4] In 1974 a record share of 10 per cent of total sales went to other systems due to exceptionally dry conditions in these other areas.

electric or wood waste generating capacity.[5] Part of this enlarged share of the electricity field is accounted for by B.C. Hydro's acquisition of ten small electric utilities during this period.

In forecasting future demand growth, B.C. Hydro relies on the methodology it claims to have employed successfully in the past. This process involves extrapolation of past growth trends, modified by known or expected developments in energy use on a regional, customer class, and provincial basis. Factors studied include numbers of customers based on population trends, changes in per customer usage, economic trends, and known and probable industrial developments. Expected changes in the price of electricity are not explicity included in this analysis. The resulting short-term energy and peak demand forecasts are then extended to five, ten, or fifteen years for system planning purposes.

In its 1975 Report of the Task Force on Future Generation and Transmission Requirements (1975b), B.C. Hydro develops two alternative econometric methodologies for demand forecasting. In the first, the demand for total and electric energy in B.C. is regressed on the real Gross Provincial Product for the past 20 years. The resulting energy-product coefficient, reduced slightly to take account of anticipated structural changes in the B.C. economy and higher energy prices, is then applied to a forecast of real G.P.P. in order to determine future electricity demand.

[5] The two major industrial suppliers are the Aluminum Company of Canada (Alcan) and Cominco with 18 and 9 percent, respectively, of the provincial electrical energy capability. Both use hydro-electric sources and help supply regional requirements with their surplus capacity.

The alternative econometric approach was performed by Dr. John Wilson (1974), an outside consultant. Using pooled time-series and cross-sectional data for the last ten years, he regressed electrical energy demand on price (both its own and that of substitute forms of energy) and on economic growth variables. In this way, changing prices were explicitly considered in demand projections. In determining its official electricity demand forecast in the 1975-1990 period, B.C. Hydro employed its conventional forecasting methodology. Total electrical energy demand (including system losses and the need to supply shortages anticipated by a private electrical utility) supplied by B.C. Hydro was expected to increase by an average annual rate of 9.3 percent over this period.[6] By assuming a constant system load factor, peak demand was anticipated to rise at the same rate.

By way of comparison, B.C. Hydro's median electric energy demand forecast using the adjusted energy-product coefficient (which assumes population and economic growth rates equivalent to those in the 1953-1973 period) was 8.6 percent. The Wilson study, with its explicit consideration of prices, was lower still.

2.2.2 System Planning

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[6] B.C. Hydro's September 1976 comparable electrical energy forecast (using the same 1975 base) assumes a growth rate of 7.7 percent. I shall use the 1975 estimates in this study, both because I have been unable to obtain full disaggregation of this new estimate and because I wish to maintain consistency with other sources of information. Appendix C, however, does use this updated load forecast.

At its formation, B.C. Hydro's electric system contained half a dozen major isolated service areas supplied by a series of relatively small generating stations. Since that time, the total demands on the system have almost quadrupled. Strong interconnections between the previously isolated sections have been forged and much larger generation projects have been added to the system. The one major load centre not yet connected with the main system (the Prince Rupert-Kitimat-Terrace area in the North-West part of the province) is now scheduled for integration in 1978. Other very small load centres scattered throughout the province are supplied primarily by local diesel generators. For the purposes of this paper, we will analyze only the integrated electric system since the isolated systems, following the 1978 North-West connection, will account for less than one percent of the forecast electrical energy demand facing B.C. Hydro.

Before describing the integrated system as it now exists, it is important to extend a critical distinction made earlier. Just as demand forecasters are careful to differentiate between electrical energy and peak demand requirements, system planners talk in terms of the energy capability and peaking capacity of the system. The former refers to the total quantity of kilowatt-hours that can be produced and delivered by the system in a given time period. The latter describes the maximum rate at which energy can be generated and distributed and is measured in kilowatts.

As of March 31, 1976, B.C. Hydro's integrated system was supplied by 29 hydro-electric, one conventional thermal and 4 gas turbine plants accounting for 77, 18, and 5 percent, respectively, of generation peaking capacity. Almost 50 percent of this capacity is installed in the Shrum Generating Station on the Peace River. This electricity is stepped up at sub-stations and transmitted at 500,000 volts to the load centres in the provincial grid. It is then stepped down at additional transformation sub-stations and carried through sub-transmission and distribution networks to be delivered to each customer at the appropriate voltage level. A B.C. Hydro map (Appendix B) outlines the electric transmission system with existing facilities and planned additions.

The electrical energy demand facing B.C. Hydro varies throughout the day and year. The system's annual peak demand usually occurs between 5:00 and 6:00 p.m. on a winter weekday. Its minimum level, less than half that of the peak, is generally reached before 6:00 a.m. on a holiday. To meet these variations, the Authority attempts to operate its system in a cost-minimizing fashion within the technical constraints it faces. The base load is supplied by large hydro-electric projects such as the Shrum plant on the Peace River. As demand rises, more expensive hydro-electric sources are connected. The additional Units [7] to meet demand during the peak period are also primarily hydro-electric although expensive gas turbines are occasionally needed. The natural gas (or oil)- fired Burrard thermal plant is generally used in the winter and spring to make up anticipated shortfalls between total electrical energy demand and that which

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[7] Units in generating plants will be capitalized throughout this paper to distinguish them from the more general use of the term.

can be supplied by hydro-electric sources, although it too sometimes performs a peaking role.[8] The extent to which the fossil fuel fired plants are used depends largely upon water conditions. In the 1975-76 fiscal year, only about ten percent of the energy generated came from thermal sources.

Within the last year, new hydro-electric plants have been brought into service on the Kootenay and Columbia Rivers. Construction is well underway on both the Peace and Pend d'Oreille Rivers with the new power expected by 1980.

In determining future expansion requirments, B.C. Hydro looks at both the energy and peak demands it anticipates having to supply. Most of the projects it considers would add to both energy capability and peak capacity. Some, however, would produce only additional electrical energy while others add only to peaking capacity.

In the period to 1990, the major new projects providing both energy and capacity being seriously contemplated are hydro-electric plants on the Peace and Columbia Rivers and coal-fired stations in the Hat Creek and East Kootenay Regions. Diversions of rivers through existing facilities on the Peace and Columbia Rivers are the energy-only projects being considered. Installation of new turbines and generators at existing or planned hydro-electric sites represent the main capacity-only projects possible. In addition, two gas turbine Units are contemplated for Vancouver Island to meet possible local

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[8] Recent federal controls have required that any electricity exports generated at Burrard be priced at greater than the equivalent gas export price. This has reduced exports somewhat, although this high price serves as little deterrent during very dry periods in the U.S. Pacific Northwest.

shortages pending completion of new underwater transmission capacity from the mainland.

Beyond 1990, nuclear power, more distant and/or expensive hydro-electric sites and less accessible coal deposits are being considered as possible generation sources.

In selecting these projects from a larger group of potential electricity sources, B.C. Hydro takes explicit account of the earliest possible in-service dates and the expected capital and operating costs to the Authority associated with them. The comparative costs of each of these projects (including the associated transmission costs) over their lifetime is calculated, using various discount rates. The resultant least-cost rankings are then adjusted according to legal, environmental or social considerations not already included.[9]

These tentative project choices are then used to develop alternative generation and transmission programmes required to meet the technical criteria established for energy and peak load requirements over the forecast period. These programmes are subsequently analyzed with reference to economic criteria to establish the optimal plan.

The technical criterion in effect for determining energy capability is that the firm capability of the system be equal to or greater than the forecast electric energy demand. Firm energy

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[9] Although not yet part of its formal decision-making process, B.C. Hydro has recently completed a detailed benefit-cost analysis employing economic principles. This study (1976c) attempts to help choose between different generation projects by explicitly considering both the quantifiable and non-quantifiable regional and environmental impacts in addition to the traditional direct costs and benefits of the alternative projects.

capability is essentially the total energy production possible from hydro plants during critical water conditions (the lowest five years of recorded stream flows) plus thermal plants operated at their maximum annual energy capability plus power purchases made in accordance with firm contracts. To the extent that actual water conditions exceed the critical standard (average conditions increase energy capability some 5 to 10 percent), thermal generation is cut back to reduce operating costs.

The technical criterion now adopted for determining peak capacity requirements is the loss-of-load probability method. The essence of this approach is that excess peak capacity is built to the point where the probable occurrence of system peak demand exceeding system peak capacity is one day in ten years. This recently adopted criterion replaces one which had suggested relatively more reserve capacity in the 1970's and relatively less in the 1980's. It is the standard required of all 18 members in the Northwest Power Pool.

Having determined that the alternative programmes meet these two technical criteria, B.C. Hydro then compares them on the basis of discounted cash flow analysis, using nominal expenditures and discount rates. The cash stream includes original capital expenditures, operating expenses and, at least theoretically, the cost of plant replacement and subsequent operation at intervals equal to its estimated useful life. Essentially, the programme with the highest internal rate of return (and also above the minimum acceptable nominal rate of 15 percent) is chosen as the most economic.

As a result of this analysis, the Task Force recommended a generation and transmission plan through to 1990. The major combined energy and capacity projects, with their suggested in-service dates, were as follows: Revelstoke, on the Columbia River (1981), Hat Creek coal plant Stage 1 (1983), Stage 2 (1986), and East Kootenay coal plant (1989). The energy-only diversion projects were recommended as soon as legally and/or environmentally feasible: Kootenay River Diversion to the Columbia River (1984) and McGregor River Diversion to the Peace River (1985). The capacity-only additions of turbines and generators at existing or planned hydro-electric sites were to begin in 1985 and average one a year to 1990. Major new transmission projects were associated either with transporting electricity from the new combined energy and capacity projects or with more strongly integrating the system and meeting growth in various load centres.

B.C. Hydro has not as comprehensively analyzed the need to expand sub-transmission, transformation and distribution facilities. This is undoubtedly due to the dominant role played by the generation and transmission programme which the Authority expects, in the 1977-1981 period, to require 51 and 19 percent respectively, of the electric service's capital budget. It appears, however, that as one moves further from the generation level, capital costs become increasingly related to peak capacity considerations and to the characteristics of individual customers.

Forecasted energy capability shortages are clearly driving the expansion of the generation programme until the latter part of the 1980's.[10] Hydro's explanation for this is that for hydroelectric sources, generating capacity is sometimes installed specifically for the purpose of assuring the full utilization of available hydraulic energy under varying stream flow conditions, thus resulting in excess peaking capacity. This surplus is expected to disappear as thermal energy sources begin to play a more important role in the system.

2.2.3 Financing

At its formation, B.C. Hydro acquired all the outstanding debt of the two organizations from which it sprang, and compensated the equity owners of the private corporation. Its subsequent expansion has been financed very largely by debt instruments, with internally generated funds providing most of the balance. Provincial government grants, in the form of rural electrification assistance and transit operation subsidies, and capital contributions from some customers have provided relatively minor additional amounts. Funds received as a result of the Columbia River Treaty have paid for most of the three storage dams, with the deficit to be charged to the electric service. After netting out the Treaty dams, this service accounts for approximately 90 percent of B.C. Hydro's net property in service.

The Authority's outstanding debt in the form of bonds has risen from .8 to 4.0 billion dollars between 1963 and 1976. A large share of this is held in provincial government trust funds

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[10] The system is described as being 'energy-critical' (as distinct from 'capacity-critical') under these circumstances.

and the Canadian Pension Plan Investment Fund, although B.C. Hydro is being forced to rely increasingly on both private placement and public issues in Canada and the United States. The interest rate on this existing debt ranges from 3 1/4 to 10 1/2 percent with an embedded average of 7.4 percent in 1976. The average effective annual interest cost of new issues during the 1975-76 fiscal year exceeded 10 percent for the first time.

As established under its 1964 Act, all existing securities of the Authority are backed by the Province and sinking funds are provided for the retirement of long term debt. At present, B.C. Hydro's share of net outstanding debt guaranteed by the Province of British Columbia stands at 69 percent.[11] Each year's new issues must be approved by the Legislature through an amendment to the borrowing ceiling set in the 1964 Act. The sinking fund payments on debt issued within the last five years are designed to approximately fully refund the principal. However, much of the debt acquired or issued by Hydro is linked to payments which will cover less than half the amount due at maturity.

B.C. Hydro's net income has fallen in recent years to the point where only a special provincial subsidy last year prevented a loss. As a result, internally generated funds have been providing an increasingly smaller percentage of the Authority's capital requirements. In the 1975-76 fiscal year,

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[11] The other Crown corporations with net outstanding debt guaranteed by the Province, with their share of the total in brackets, are: B.C. Railway Company (12), B.C. School Districts Capital Financing Authority (12), B.C. Regional Hospital Districts Financing Authority (4). The provincial government itself has no net outstanding direct debt.

only 10 percent of these requirements were met from internal sources, even after the special subsidy. This is reflected in the fact that the ratio of debt to retained earnings is now 95:5. In an attempt to improve its credit-worthiness, B.C. Hydro has embarked on a programme to increase substantially its net income to the point where it will approximate one-third of its net interest obligations.

The process of forecasting cash requirements is basically one of taking the capital expenditure figures provided by the system planners and adjusting them to include net financial obligations. In the next five years, for example, B.C. Hydro estimates capital expenditures on its system of 5.0 billion nominal dollars (93 percent of which will be in the electric service) plus .3 billion nominal dollars to meet long-term debt maturities and sinking fund requirements. It anticipates that between 14 and 23 percent (depending upon the degree of passenger transportation services subsidies) will be generated internally. The balance would be raised in the bond market.

2.2.4 Rate Setting

B.C. Hydro does not appear to have been given any formal direction on the question of the level or structure of its rates. The Power Act, applying to the former British Columbia Power Commission, explicitly stated that "the Commission's rate schedules shall be designed to permit and encourage the maximum use of power" (British Columbia Legislature, 1960). The subsequent British Columbia Hydro and Power Authority Act remained silent on this issue.

In its first year, B.C. Hydro introduced two rate reductions and standardized both residential and small commercial electric rates throughout the province. A bulk power rate was introduced for large industries, resulting in the addition of significant loads to the system. A new uniform extension policy applicable to all residential and farm electric customers was initiated in which B.C. Hydro paid a greater proportion of the initial costs of extensions. In the words of the 1963 Annual Report, "the adoption of new extension policies and the introduction of lower power rates are designed to encourage the development and expansion of industry in British Columbia" (B.C. Hydro, 1963,6) .

Electric rates continued to fall in each of the next three years. Two all-electric rates were introduced to encourage the use of electricity for heating homes and small commercial premises. Unlimited "one-cent power" became available to all residential customers in 1965 and was designed to "encourage home owners to make greater use of electric applicances, air conditioning, decorative lighting and electric heating". (B.C. Hydro, 1965,6)

In 1967 electric rates were raised, a move repeated in 1970, 1974, 1975, and 1976. Most of these increases ranged between 10 and 20 percent although the large users were hit with hikes of more than 50 percent between 1974 and 1976. The 1974 Annual Report indicated that sales promotion activity had been replaced with programmes designed to promote the wise and efficient use of energy.

There are now essentially three basic customer rate classes: residential, general and bulk. Although a variety of other rate classes do exist, their sales volume is relatively small and they are often closed to new users. In 1976, the standard residential rate was based on a simple two block declining energy charge. The first 550 kilowatt-hours (KWH) per two month period were billed at 4.6 cents (46 mills) each with all additional at 1.7 cents each. The minimum charge for the period was $6.14, equivalent to 133 KWH at the higher price. Approximately eighty percent of all users in the class reached the second block. Average energy use during this two month period was 1400 KWH, yielding a residential average price of 2.8 cents per KWH.

The general service class has two sections, depending upon the customer's peak monthly demand. For more than 90 percent of the customers in this class, peak demand is below a level considered economic for the installation of a meter separately measuring energy and peak demand. In 1976, these customers were billed on the basis of an energy charge consisting of four declining blocks (starting at 5.35 cents and falling to 1.5 cents per KWH) and a fixed minimum charge of $8.50 for two months. The average price for this group was generally higher than what it would have been for the same consumption under the residential rate structure. The vast majority of commercial customers fall within this group.

For the customers with a larger peak demand, essentially the large commercial and smaller industrial consumers using over 70 percent of the energy consumed by the general class, a two part tariff is in effect. In 1976, peak demand for the month was billed on an increasing four part block rate. Total energy demand in this period faced a declining six part energy charge. The net effect of these two opposing movements, given a fixed load factor, was for the price per KWH to generally fall with increased consumption. Average price per KWH for this group was generally below that for either the residential or commercial customers. The minimum monthly charge was the greater of a fixed amount or 75 percent of the peak demand during the winter months.

The third class, bulk customers, have generally been the largest group in terms of annual energy sales. Taking power at levels of at least 60,000 volts, they comprise large industrial concerns such as pulp and paper mills, electro-chemical plants, oil refineries and mines. They require either one or two year's notice of a change in rates and faced average increases ranging from 55 to 70 percent between 1974 and 1976. Rate increases for the next two years approximating 10 percent annually have been announced for these customers.

The peak demand charge for bulk customers is at a flat rate and currently comprises some two-thirds of the average customer's total bill. Peak demand calculations use the "ratchet" principle in that they are based on the greater of that month's peak demand and 75 percent of the highest peak demand in any of the eleven preceding months. In 1976, all energy was sold at .3 cents per KWH. Monthly minimum charges were based on the peak demand as determined above, while the annual minimum charge was based on peak demand "ratcheted" only to the winter months. The average price of electricity for this customer class approximated one cent per KWH.

Other smaller rate classes which we shall not deal with in this study cover irrigation, street lighting, rooming houses and areas with special rates and those served by diesel generators. B.C. Hydro does not now offer any interruptible service, with reduced rates, for its large industrial customers.

In determining rate levels and structures, B.C. Hydro has assumed the following power pricing goal:

> To sell power to customers at rates based on costs of service; such costs to include all costs required to meet statutory obligations and Government policy directions and to ensure the continuance of B.C. Hydro as a financially independent and viable corporate entity.
>
> (B. C. Hydro, 1975b,16)

The Authority reviews rates for its electric and gas services annually in the light of its projections of operating results and requirements for capital expenditures. Rate levels are set for these services prior to the commencement of a fiscal year to ensure that losses will not be incurred in that fiscal year. The desired surplus or profit for the forecast year depends on the extent to which internally generated funds are to finance future expansion, and is now slated to reach 30 percent of net interest payments within six to eight years. The Authority's most recent Statement of Income, from which annual net income is determined, is contained in Appendix A. Standard historical cost accounting procedures are followed, with depreciation being calculated on a straight line basis and gross interest on debt being reduced by interest during construction and income from sinking fund investments. Salaries and net interest on debt each account for approximately 30 percent of expenses, followed by materials and services, depreciation and taxes.

These costs are quite finely disaggregated within B.C. Hydro. Operating and capital costs are assigned to the various functions within each service. For the electric service, these costs are allocated between the capacity and energy components. Finally, each class of customers is given its share of these costs. Rate levels for each class are designed to cover completely the projected "cost of service" based on this "fully distributed" average historical cost accounting method, plus a share of the desired annual surplus.

The methodology employed to allocate costs between the energy and capacity components is of fundamental importance. At present, all costs associated with transmission, transformation and distribution as well as the capital costs of the generating equipment (turbines, generators, etc.) are categorized as capacity. The generation costs not associated with generating equipment, such as the dam, are allocated between energy and capacity based on plant factor, the ratio of the average load on the plant to its capacity. Thus a reservoir which is used to supply base-load energy has much of its cost allocated to the energy component, unlike a peaking plant. Some operating costs at the generation level, such as fuel and a share of labour and water licence fees, are also classed as energy-related.

The result of this approach is that the great majority of costs in the electric service are attributed to capacity, helping to reduce the share of costs borne by the high load factor customer classes. Historically, the commercial customers have generally borne somewhat more, and the residential customers somewhat less of their share of costs based on this allocation procedure.

The actual design of the rate structure to recover the above costs for each customer class does not appear to be as clearly a defined process. Considerations of revenue stability, future cost structures, permissible rate of change and political impact all weigh heavily on the rate maker's mind in addition to the "cost of service" information. Bulk rate customers, with their separate flat charges for energy and peak demand, face an energy charge twice that calculated under the "cost of service" method, with a corresponding reduction in the peak demand charge. This adjustment would appear to result from an uneasiness about the extreme imbalance between these two components under this allocation scheme. Smaller industrial customers seem to have their energy and capacity charges designed to approach those of the bulk users as their consumption increases, although the marginal energy charge in 1976 never fell below almost twice that of the large users. For the residential and commercial customers, with their declining block rate energy charges, much of the capacity or fixed costs are placed on the initial block and minimum charge, with tailing blocks reflecting an increased share of the energy costs.

The 1977 rate hikes seem to indicate an increased emphasis on the energy component of the bill. Thus bulk users will see their energy charge double to .6 cents in 2 years , while their peak demand charge increases only marginally. Residential users face an increased tailing block of 2.0 cents per KWH although a new service charge of $3.00 each two-month period will have the biggest impact on small users. The only rate restructuring evident in the increase for the general service class is the introduction of a monthly service charge of $2.25, again raising costs relatively more for the smaller accounts.

These rate structure changes reflect B.C. Hydro's longer term intention of "flattening" the rates for energy consumption while raising the initial charge designed to cover fixed expenses. In a recent statement, the Chairman of B.C. Hydro claimed that "electrical rates should be neutral in their effect upon use with service charges completely separate and a flat rate for energy used as the second component of the customer's bill" (Bonner, 1977). He went on to say that, if fully implemented, this would involve a service cost component (for residential customers) of about $8.65 per month to which an energy charge would have to be added.[12] Because of the burden this would place on the small user, he stated that this "ideal neutral rate" would probably never be achieved, but that future adjustments would aim at further rate neutrality as between incentive and disincentive to use.

2.3 Summary

This chapter has attempted to present the necessary background on B.C. Hydro to proceed with an economic analysis of the determination and implications of an appropriate rate

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[12] If the revenue requirement for the residential class were to be met, this would imply a flat energy charge of 1.0 cents per KWH based on 1976 figures.

structure for the Authority. It has discussed the institutional framework within which B.C. Hydro operates and has focussed on the Authority's past and present policies in key areas of the electric service.

The essence of the electrical planning process at B.C. Hydro is as follows. The demand forecasting section produces a 10 to 15 year forecast of expected energy and peak demand to be met by the Authority. The system planning group designs a least-cost expansion and operating plan subject to certain technical, legal and environmental constraints to meet this forecast demand. The financial team is advised of the capital requirements this will entail and calculates how best to raise the necessary funds. Finally, the rates department projects the necessary rate levels and structure for each class of customers in an attempt to meet fairly the revenue requirements of the Authority. The linkage between each of these functions is explicit. The connection between the rate structure and demand forecasting is not.

3. THEORY AND METHODOLOGY OF MARGINAL COST PRICING

3.1 Emergence Of The Theory Of M.C.P.

Economic theory suggests that a profit maximizing monopolist would tend to produce less, and charge more, than would be socially optimal. Aggregate production would be determined by setting marginal cost equal to marginal revenue, with selling price being a function of the demand for the product. If the product's aggregate market could be divided into submarkets with different price elasticities, then price discrimination would be attempted whereby those sectors with the most inelastic demand were charged the highest price. In addition, where possible, rate structures within each submarket would be designed with marginal price below average price so that the monopolist could capture some of the consumer surplus associated with downward sloping demand curves.

Because of the economies of scale inherent in their capital-intensive production processes, most public utilities were considered to be so-called "natural monopolies". Electric utilities were assured of this monopoly position, but were carefully watched to ensure that they did not make unwarranted profits. The primary focus of rate setting became to ensure that the resulting total revenues were adequate but not excessive. In the case of privately-owned electric utilities, this adequacy was often determined through formal regulation based on an approved rate of return on an historical cost rate base.[13] For publically-owned or Crown corporations, the process was usually less formal and involved ensuring that net accounting income was approximately equal to that required to assure the long term financial viability of the utility.

In designing rate structures consistent with this total revenue objective, practitioners generally believed that prices should lie somewhere between the "incremental cost" and the "value of service" of the incremental load.[14] Although never very clearly defined, "incremental costs" were generally held to be below average costs in both the short and long run, thus suggesting a declining block rate structure within each customer class. The "value of service" concept, intended to set an upper limit on price, was essentially an inverse measure of the elasticity of demand for electricity. The large industrial users, for example, with alternative sources of energy available to them, were said to have a low "value of service". Thus price discrimination between classes usually led to lower prices for higher use customer classes. The combined result was generally a declining average price for electricity as consumption increased, both within and between customer classes. The expanded use that such rate structures encouraged was designed to benefit all by leading to lower average costs, and hence prices, in the future.

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[13] Considerable discussion in the economic literature has centred around the question of the possible distortions in the relative intensity of use of various factors of production resulting from the regulatory method. See Helliwell (1977) and Callen (1976).

[14] See, for example, the practical guide to the art of electric rate making by Caywood (1956).

Microeconomic theory tells us that a necessary condition for the maximization of society's welfare is that the marginal social benefit from the production of an additional unit of a product is equal to the marginal social cost resulting from that production. If it is assumed that an individual's demand curve represents marginal social benefit and that marginal social and private costs are equal, then this condition for economic efficiency implies that the marginal price of a product should equal its marginal cost of production.[15] In this way, a consumer will be able to adjust his consumption pattern in response to relative prices so as to maximize his own satisfaction while at the same time ensure that society's scarce resources are being used most efficiently. Natural economic forces will act to satisfy this condition in a perfectly competitive market situation, but will be lacking in the presence of a monopoly. If, in fact, externalities do exist on either the demand or supply side of the formulation, then we must resort to the original conditions for economic efficiency employing marginal social costs and benefits.

The presence of a technical externality in the electric utility industry, the increasing returns to scale experienced in the past, led to what seemed to some economists to be an impossible dilemma in designing an optimal rate structure. With

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[15] This discussion deals only with economic efficiency - how to allocate resources so that they cannot be further adjusted to increase satisfaction without making at least one party less satisfied - and ignores the distribution of resources within society. In order to derive an optimal social welfare position which includes considerations of both efficiency and distribution, an explicit social welfare function is required.

marginal costs below average costs, the equating of prices with marginal costs would not meet the total revenue requirement.[16]

In 1938, Hotelling startled the world of utility rate theory by advocating that the economic efficiency criterion become the prime consideration in rate setting. Prices would be equated with short run marginal cost, and any revenue shortfalls would be supplied from general government revenues. Considerable debate over this proposal ensued for the next 15 years, with practitioners rejecting the scheme and academic economists tending to favour long run marginal cost as the basis for determining an optimal resource allocation.

Within the last decade there has been considerable renewed interest in the theory of rate structures, particularly as applied to electric utilities. The circumstances of the debate have altered dramatically, with the rising real private and social costs associated with electricity generation and distribution now suggesting that marginal costs exceed average costs in many cases. Some of the issues of the earlier decades were resolved. The apparent divergence between the economic efficiency and revenue sufficiency criteria can be reconciled when it is realized that it is the <u>marginal</u> price that must equal marginal cost for optimal resource allocation. Hence adjustments in the intra-marginal price can theoretically be made which will enable both objectives to be met simultaneously. On the issue of short vs. long run marginal cost, it was recognized that in an optimal system the two are identical once

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[16] It should be recognized that the total revenue requirements in an economic sense have no necessary relationship to revenue requirements under an an historical cost accounting framework.

the marginal costs of curtailment are included in the short run costs.[17] For non-optimal systems, Turvey's (1968) suggestion of using the present value of the change in costs for a demand change effectively uses an average (weighted by the rate of social time preference) of both short and long run marginal costs.

A commonly heard argument against the use of marginal cost pricing in a particular industry revolves around the theory of the second best. This theory essentially states that no 'a priori' conclusion can be drawn as to the impact on social welfare of introducing marginal cost pricing in one industry when at least one other industry does not use an economically efficient pricing criterion. The standard reply to this argument is that one should still determine what the relevant marginal costs are for the particular industry under consideration. Then, when transferring from a partial to a general equilibrium framework, adjustments in that industry's marginal prices may be desirable from an economic efficiency perspective if significant substitute or complement products exist whose pricing practices do not satisfy this criterion.

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[17] Curtailment costs are the costs of doing without - the costs incurred by society as a result of a shortage of electricity. For an optimally designed system, marginal social curtailment cost should equal marginal social cost of adding electrical supply capacity.

3.2 Emergence Of The Methodology And Application Of M.C.P.

Although the basic theory establishing the merits of marginal cost pricing is now well established in economic circles, the application of this theory remains much less developed. Indeed, it is this apparent difficulty that has led some to reject the economic efficiency objective as a central criterion in rate design.[18]

In addition to the general debate over short vs. long run marginal costs, and the reconciliation of economic efficiency and revenue sufficiency, the electric utility literature has witnessed considerable controversy over the allocation of marginal energy and capacity costs. This has manifested itself in discussions on "peak load pricing" and the related problem of the "shifting peak".

The basic prevailing approach by economists today is to charge both marginal operating and capacity costs to users during the system's peak periods, with off-peak users facing only marginal operating costs.[19] Capacity costs are fully allocated to peak periods since it is only this demand that prompts new investment. The investment in equipment idle during off-peak periods represents "sunk costs" with an opportunity cost of zero. If there are significant variations in marginal costs within either of these periods, then a more finely structured rate schedule can be devised to correspond to these variations. Moreover, to the extent that the resulting rate structure would be expected to lead to shifts in the demand

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[18] See, for example, Lewis (1949).
[19] See, for example, Berlin (1974) and Joskow (1976).

pattern, adjustments in the rate structure would have to be made in anticipation of these movements.

The first real attempt to apply marginal cost pricing principles to an electric utility is that of Electricite de France (EDF) in the early 1950's. EDF was a nationalized power company supplying most of France with a system evenly comprised of hydro and thermal plants. The key problem in undertaking a marginal cost analysis was seen to be that of appropriately allocating the heavy fixed costs associated with the production and distribution of power. The utility recognized that the correct way to calculate marginal costs would be to compare the cost changes associated with the reoptimization of the expansion and operation of the system that would result from changes in present and future demand. EDF found the application of this approach difficult. To simplify the analysis, it assumed the existence of an optimal system with short run marginal costs equal to long run marginal costs and proceeded to calculate the short run costs. Marginal generation costs were determined from the operating costs of thermal plants and, by tracing present and anticipated transmission line flows, the effective operating costs for the hydro facilities were imputed. The marginal costs of transmission were the operating losses plus the capital costs during those periods when the line carried a full load. Curtailment costs were also estimated. The resulting rates were differentiated by time, season, voltage level and geographic location and were offered to the major customers.

Since this pioneering work, other utilities have undertaken economic analysis of their costs and have implemented rates based, in varying degrees, on marginal cost pricing principles. This approach is gaining acceptance in the United States where a number of regulatory boards have recently ordered electric utilities under their jurisdiction to move in this direction.[20] One of the more recent and thorough economic analyses of electricity costing and pricing was that undertaken by Ontario Hydro (1976).[21] The study recommended new rate structures based upon marginal cost pricing principles, and the methodology employed to determine the relevant marginal costs is representative of the approach now most common in the U.S.[22]

Like EDF, Ontario Hydro does not develop a methodology based on the pure theory of marginal cost estimation, but rather employs various "shortcuts" which involve analyzing certain parts of the electric system. Marginal generation capacity costs are essentially taken to be the annualized costs of a gas turbine peaking plant. Marginal transmission costs are all allocated to capacity and are determined by annualizing future real expenditures on transmission facilities. These costs are then divided among various broadly defined periods with most being allocated to those times with the greatest loss of load

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[20] See, for example, Public Service Commission of Wisconsin (1974) and State of New York, Public Service Commission (1976).
[21] Although the Board of Directors of Ontario Hydro has formally accepted the underlying principle that efficiency in the allocation and use of resources in producing electric energy is the appropriate pricing objective, it has not taken any position on the specific recommendations of the study.
[22] One reason for this is that National Economic Research Associates, a large New York economic consulting firm, undertook much of the marginal cost estimation for Ontario Hydro. It has performed similar work for many of the electric utilities in the United States now going through this process. Cicchetti's (1976) manual on marginal cost pricing advocates the same basic approach.

probability. Marginal energy costs are taken to be a weighted average of the highest variable cost Units associated with energy production during these different periods. All costs are those faced by Ontario Hydro and these initial estimates are not explicitly recalculated as a result of demand pattern shifts which would be expected from this change. These time-differentiated marginal energy and capacity costs are then used as a basis for setting an optimal rate structure, appropriately adjusted for considerations of revenue constraints, equity, cost of metering, etc.

3.3 Developing An M.C.P. Methodology For B.C. Hydro

B.C. Hydro has never formally adopted economic efficiency as a goal in its rate setting policy. It has, however, publicly stated that its rates are, and should continue to be, based on "costs". The current fully distributed average costing methodology used by B.C. Hydro to determine "cost of service" has no relationship with an appropriate marginal costing approach. Its prime role is to allocate accounting costs amongst various user classes to ensure that each class contributes enough revenue to enable the Authority to meet its net income objective.[23] This somewhat arbitrary, backward-looking approach

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[23] The choice of allocation method has an important influence on the relative share of total costs attributed to each class. Thus the B.C. Hydro method, with its heavy allocation of costs to capacity, favours the high load factor classes (industrial) at the expense of the low load factor consumers (residential).

is then used as a basis for determining marginal as well as average rates. It fails as an appropriate basis for setting prices consistent with the economic efficiency criterion in a number of fundamental ways.

In some cases it simply uses the wrong costs from an economic perspective. Costs external to the Authority are ignored, and resources are valued at their cost to the utility which differs significantly from their true opportunity cost in some instances. Commitments made at different times are compared directly despite subsequent inflation and differing technologies. Thus the average historical cost depreciation charge is below both its own marginal level and its inflation-adjusted average level. Similarly, the average nominal interest costs used in the "cost of service" methodology are substantially below their marginal nominal cost.

In other cases, B.C. Hydro's cost allocation is done in an arbitrary way and important cost responsibilities are lost. The split between energy and capacity is on the basis of existing plant rather than on the cause of building new facilities. Time-differentiated costs are buried since all costs are lumped together and then averaged.

These weaknesses in the costing methodology are further intensified by the manner in which it is applied in rate setting. The "front end loading" of the fixed charges for residential and commercial customers results in marginal energy rates below even the costs determined on the fully distributed average cost method. For the larger customers, the heavy peak demand charges are based primarily on the individual customer's demand pattern with little regard for its coincidence or otherwise with that of the system.

Unfortunately, the techniques that have been used to determine marginal costs for other electric utilities have some of these weaknesses and do not appear, in any case, to be particularly relevant for B.C. Hydro. This stems in part from B.C. Hydro's very large and growing hydro-electric generation base, which distinguishes it from other systems in two significant respects. The first is the extremely capital-intensive nature of the system with consequentially low marginal operating costs. The second relates to the energy-critical nature of the system. Most current marginal costing techniques implicitly assume the existence of an economically optimal electrical system that is both energy and capacity-critical and in which the marginal costs are independent of the size and direction of the demand variation. These assumptions may be reasonable for some systems and thus yield a good approximation of marginal costs. However, they are certainly not valid for B.C. Hydro.

The B.C. Hydro system is not optimally designed, in the economic sense that the short run average cost curve is currently above the long run average cost curve, because of the post-1973 major increases in the price of petroleum. Hence new hydro-electric projects are estimated to produce cheaper energy than the gas-fired Burrard thermal plant (when gas is priced at its opportunity cost). Thus to rely exclusively on the marginal operating costs of Burrard as the appropriate marginal energy rate would overestimate these costs.

The fact that the B.C. Hydro system is not currently both energy and capacity-critical also has interesting implications. New generating projects that produce both energy and capacity, but that are advanced or retarded only because of changes in the energy demand forecast, should have the resultant cost changes allocated solely to the energy component. So too with the associated transmission lines linking the new project to the load centre, a procedure counter to both the "cost of service" and the current marginal costing methodologies. Changes in the peak demand forecast will affect the timing of the capacity-only projects in the 1980's, but these cost changes should be appropriately discounted in setting today's rates.

The third false assumption concerns the linearity and symmetry of the response of costs to demand changes. For example, an increase in the annual energy demand will generally lead to increased use of the expensive Burrard thermal plant. However, a substantial annual decrease will first be met by shutting down Burrard and then by spilling water over dams (assuming no export market is available), with very little cost savings to Hydro or society. Other non-linearities will be evident because of indivisibilities and somewhat arbitrary technical criteria.[24]

As a result of these and other important weaknesses in the current marginal cost pricing methodology, a different approach

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[24] For example, the technical energy or capacity criteria may cause a small change in anticipated demand to automatically trigger the advancement of a project by a full year. An economic analysis might suggest society would be better off facing the increased risks of an electricity shortage than incurring the extra real costs of advancing the project by a year.

is required. The basic method that we will adopt is that outlined by EDF and later reformulated and clarified by Turvey (1968). It revolves around the fundamental meaning of marginal cost in a dynamic context - the change in the present value of society's costs associated with a marginal change in the present or future demand for electricity. Using computer simulation techniques, we shall build a model which will plan and operate B.C. Hydro's integrated system in a cost-minimizing way, subject to various technical constraints, based upon a given electrical demand forecast. A change in the demand forecast will then be introduced and the operation and design of the electric system will adjust itself accordingly. The present value of the associated cost difference divided by the present value of the changed quantity of kilowatt-hours will yield today's marginal cost per kilowatt-hour resulting from the change. By altering the system load factor of this hypothetical change in demand, the marginal cost can be appropriately allocated between the energy and capacity components. For example, the additional costs resulting from a demand increase that falls partly on the system's peak period rather than the same increase occurring totally in off-peak periods will yield the marginal costs associated with a change in peak demand.

All costs used in this economic analysis will be expressed in real terms using 1976 dollars. A one year delay in the commencement of a construction project will, all things being equal, not affect its real cost despite a likely increase in its nominal cost due to inflation. It is the relative cost of the project, in terms of the foregone alternative uses of the resources employed, that is important.[25] In fact, the one year delay will, all things being equal, reduce the cost of the project to society (as viewed from today) due to the discounting of future costs. These costs should be discounted by society's real rate of social time preference, the premium we attach to present over future consumption.

The costs we are interested in are opportunity costs - what society would have received, and hence must forego, had the resources been put to alternative uses. Those investments already made are "sunk costs" with zero opportunity cost and will not be included in this analysis. It is the variable operating and future investment costs that have a positive opportunity cost and which will be focussed upon here. The present value of these costs will rise (fall) to meet a demand increase (decrease). The economic costs used in this analysis will deviate in several important ways from costs as measured by B.C. Hydro.

With the exception of fuel, all the Authority's operating costs will be assumed to be priced at their full opportunity cost.[26] Natural gas will be valued at its export price, more than twice what B.C. Hydro now pays to burn gas in its thermal plants. This is particularly fitting since gas export contracts at this price are not being fulfilled because of upstream demand

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[25] To the extent that "money illusion" exists, the real costs may, in fact, vary because of inflation. It is difficult to determine 'a priori' the net effect of this illusion since it might raise real costs in some cases (eg. cost of capital) and lower it in others (eg. cost of labour).

[26] To the extent that resources used by B.C. Hydro would otherwise be underemployed, this assumption overestimates true opportunity costs. An obvious example is a construction project in a high unemployment area.

in British Columbia. Similarly, future coal production from B.C. deposits will be valued at the highest net price that it could have received elsewhere. Annual water licence fees will be implicitly assumed to represent the opportunity cost of the river affected by the power project.[27]

Construction cost estimates will be appropriately adjusted in light of past experience with changes in real costs from preliminary planning to final estimate to actual cost. Although the relative cost of each project is all that is important when selecting <u>which</u> project to proceed with, the absolute cost of the least expensive one is required to decide <u>whether</u> the project should proceed at all. These estimates will include expenditures required to reduce some of the negative externalities associated with the projects.

Depreciation charges will be based on the life of the average Canadian non-residential investment, rather than on the expected life of the particular asset being depreciated.[28] Had the capital not been invested in a dam, for example, it could have gone into home insulation, equipment modernization or petroleum development. The shorter lives of the capital in these projects would have ensured a faster repayment and subsequent combination with other resources to raise social welfare. Straight line depreciation over the "opportunity life" of the

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[27] The validity of this assumption is suspect since water licence fees are uniform throughout the province - they do not respond to the differing alternative use values of different dam sites. This weakness will be partially overcome by including the additional expenses required to mitigate some of the external costs associated with each project.
[28] I owe this approach to Helliwell (private discussion) and Gaffney (1974, 1976).

investment will lead to a constant charge in real terms, or one whose nominal level rises each year with the rate of inflation.[29]

In determining the appropriate real cost of capital (mainly interest expense), the opportunity cost concept is again employed. Investment funds being spent by B.C. Hydro represent, to some degree, money being diverted from investment in other sectors of British Columbia. To the extent that this foregone investment would have been in the private sector, it would have generated additional returns to society in the form of corporate taxes on income and capital.[30] These foregone returns to society from alternative use of the investment funds should be included in the opportunity cost of capital.

There are several other costs to society which are not reflected in the cost of capital actually faced by B.C. Hydro. Funds borrowed in Canada will tend to push up interest rates which will reduce other investment with direct or indirect costs to British Columbia. Capital borrowed in the international market will tend initially to raise the value of the Canadian dollar (under a flexible exchange rate) with negative implications for B.C.'s heavily export-oriented industry. Also, the guaranteeing of the B.C. Hydro debt by the Province has a shadow price associated with it in terms of reduced availability and/or higher price of capital for other government-backed

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[29] This is in contrast to the existing straight line depreciation method which yields constant nominal (falling real) annual charges. This reduces the quantity of internally-generated funds and may lead to "capital exhaustion".

[30] It might also have generated additional returns from school taxes since B.C. Hydro has a partial exemption from these local taxes.

projects,[31] as well as fewer financial policy options open to the provincial government. This shadow price could be reflected in an interest premium over the nominal coupon rate.

In this paper, the real opportunity cost of capital will be taken to be the average Canadian before-tax real cost of capital and will be applied to the net (undepreciated) real capital stock. It exceeds the real rate of social time preference, approximated by the real after-tax returns on virtually risk-free bonds, used to discount aggregate future costs.[32] The real social time preference rate represents society's unwillingness to exchange future for present consumption, while the real opportunity cost of capital reflects the alternative returns society would have received from investment of the funds elsewhere. The two are separated by a tax and risk wedge. The use of the two different rates differs from the practice of B.C. Hydro and others where the rates are combined into a single social discount rate.[33]

Once this basic framework has been established, we shall be interested in determining the relevant marginal costs associated

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[31] This problem has become particularly acute in Ontario where the provincial government recently ordered Ontario Hydro to cut back over $5 billion in its proposed capital budget to 1985 because of concern over the strain the associated borrowing would have imposed on Ontario's credit. There are some indications of concern in Victoria about the size of B.C. Hydro 's future borrowing plans. This may be well based in view of reports of future large capital requirements by the provincially-owned B.C. Railway Company.

[32] The idea of using separate rates of social time preference and of cost of capital follows Campbell (1975) and Marglin (1963). For a discussion of the assumptions implicit in such an approach, see Weisbeck (1976).

[33] The standard real discount rate used by B.C. Hydro is 10.0 percent. In this analysis, the real opportunity cost of capital will be 10.5 percent and the real rate of social time preference will be 5.0 percent.

with demand shocks of various sizes, direction and duration. Of particular interest will be shocks of a constant size extending from the present to the end of the simulation period. It is this decrease in costs which society will face as a result of a customer of B.C. Hydro making a net electricity-saving adjustment to his capital stock. Only if this customer faces a marginal price equal to this marginal cost will society's resources be most efficiently used in the long run. Adjustments can then be made to this basic marginal cost and price in light of the impact of shorter run demand variations.

This analysis will concentrate on the bulk power side of B.C. Hydro's integrated electric system - the generation and transmission sectors. The Authority's own understanding and analysis of the lower level transmission and distribution system is not as thorough as for the bulk sector, and very little published information is available to the independent researcher. As we have seen, however, it is the bulk system that is responsible for two- thirds of Hydro's total investment programme in the next 5 years, as well as being the sector that distinguishes it from other electric systems. Consequently, we shall focus on the marginal costs associated with serving large customers at high voltage levels, although estimates will also be made of the additional costs involved in supplying the smaller customers in the system.

3.4 Summary

In this chapter, we have traced the development of the theory and methodology of marginal cost pricing, particularly as it applies to electric utilities. In the last section we have outlined the basic approach that will be used in the next chapters to calculate the appropriate marginal costs for B.C. Hydro's electric system.

The theory of marginal cost pricing as an efficient way of allocating society's scarce resources is now well established and accepted, at least amongst economists. The methodology for determining and implementing such a theory remains somewhat less developed. The rate setting procedures currently in use by B.C. Hydro do not claim to be, and are not, based upon such a principle. The marginal cost pricing methodology being developed by Ontario Hydro and other North American electric utilities may provide reasonable approximations in some instances, but will not generate meaningful results in the case of B.C. Hydro. The methodology developed in this paper relies upon the basic definition of marginal cost in the dynamic sense, and employs explicit economic costs in its analysis.

4. THE STRUCTURE OF THE MODEL

4.1 Introduction

In this chapter, we describe the computer simulation model designed to estimate marginal costs for B.C. Hydro's integrated electric system. We begin by providing an overview of the model and its component parts. Subsequent sections contain more detail about each of these parts, providing, where appropriate, important background on the theory, assumptions, calculations and modelling involved.

The basic function of the present model is to take exogenous engineering and financial data and, given a future electrical demand projection, determine the average accounting and marginal economic costs resulting from the optimal design and operation of the B.C. Hydro system. The model operates on an annual basis from 1975 to 2059 and has the ability to bring on additional generation projects sufficient to meet a quadrupling of the 1975 level of demand.

The values for the initial year of the simulation period are based on actual figures reported in B.C. Hydro's Annual Report for that year. Future demand and cost estimates are derived largely from information contained in the 1975 Task Force Report (B.C. Hydro, 1975b). Financial data are primarily from a recent Prospectus of the Authority (B.C. Hydro, 1976b). Clarification, updating and more detail were provided by numerous officials within B.C. Hydro.

The model begins by taking information contained in two policy subroutines - POLD1 and POLS1. The former supplies electrical energy demand forecasts and the latter information on existing and committed generation projects. Subroutine DEMAND is then called to calculate peak demand requirements and to introduce any changes in future demand forecasts.

By far the longest and most detailed subroutine in the model is SUPPLY. It contains engineering (energy capability and peaking capacity) and economic (investment profile) data for each major generation and transmission project. It also has information on the investment required for downstream facilities (sub-transmission, transformation, distribution, etc.) to meet increased electrical demands. Subroutine MCOST contains the operating costs for each type of generation facility and, using the information on each major project from SUPPLY, is able to perform an economic analysis of these projects.

The resulting least-cost ranking of potential projects is incorporated in subroutine APPROVE. This subroutine compares future <u>expected</u> energy and peak demand with future <u>expected</u> energy capability and peak capacity. When a shortfall in either the energy or capacity component is forecast, it approves the next least expensive project in time for production to commence when required. Subroutine SUPPLY takes this information and constructs the new system, fully accounting for various engineering and economic variables for each type of project. It also operates the system in a cost minimizing fashion in light of the current demand facing B.C. Hydro in each time period.

These decisions on the expansion and operation of the system are fed into subroutine COSTS which calculates both the associated accounting and economic costs. The former is done by careful tracking of operating costs, local and provincial taxes, interest payments, depreciation charges, financial requirements, etc., and yields the (average historical accounting) "cost of service" of a KWH. The economic analysis determines the appropriate marginal cost per KWH using the basic approach outlined in the last chapter. Finally, subroutine RATES adjusts average prices for the various customer classes to ensure that the net income objective is met.

With that brief overview of the basic operation of the model, we turn now to examine in more detail the component parts.

4.2 POLD1 And POLS1

Subroutine POLD1 contains net electrical energy demand forecasts for the period 1975-1990 as provided in the 1975 Task Force Report. This provides a base case from which we later introduce deviations. In all cases, demand is assumed to stabilize at the 1990 level for the duration of the simulation period.

The demand forecast for B.C. Hydro's integrated electric system is split between residential, general and bulk customers and, in addition, includes the anticipated incremental requirements of a private utility.[34] The expected number of electricity customers is also read in. The net energy demand

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[34] West Kootenay Power and Light Company, a privately owned utility supplying residents in the south-central part of British Columbia, anticipates relying on B.C. Hydro for electricity when the demands facing it exceed its own generating capability.

forecast six years hence for each customer class is then fed in for each year in the period 1975-1984. This information is consistent with the net energy demand expected for each year in the 15 year period and is used later to determine when new generation and transmission projects, with lead times of up to six years, should be approved.

Subroutine POLS1 provides some basic information on the supply side of the B.C. Hydro system. Approval dates for projects already committed are read in. Adjustments in the real costs of various components of the system are made here. The real capital cost of all future generation projects is assumed to be 25 percent above the equivalent 1976 estimate although sensitivity analyses using 0 and 50 percent are performed. This adjustment is included because of a reluctance by the author to accept the accuracy of initial planning estimates in light of recent experiences by B.C. Hydro and others involved with the construction of large custom- engineered projects in North America.[35] These upward revisions could result from more detailed cost estimation, higher standards being required or unforeseen problems during construction.[36] The specific number

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[35] Witness, for example, the recent Kootenay Canal project by B.C. Hydro and the Trans-Alaska oil pipeline, Syncrude plant and Montreal Olympics by others. Arlon Tussing (1976) has compared cost estimators with accountants in that they both prefer a solid, empirically based figure to a realistic one.

[36] Examples of all three cases are to be found in current B.C. Hydro situations. Estimates for Hat Creek coal generation keep rising as more detailed design work is performed (the 1976$ estimate is 64 percent higher than the 1974$ figure ; new requirements by the provincial Comptroller of water rights will raise the costs of the proposed Revelstoke dam project; and structural weaknesses in the Site One dam on the Peace River now under construction will call for additional expenditures to correct the situation.

chosen is arbitrary since B.C. Hydro was unwilling to make available the necessary historical information to accurately test the significance of this phenomenon.

Annual operating cost coefficients for various facilities were also adjusted to reflect annual real labour and fossil fuel increases of 2.25 and 2.0 percent respectively. These figures are generally consistent with those used by Hydro (based on regression analysis and judgment) in their Revelstoke Project Benefit-Cost Analysis (1976c).[37]

Several variations of POLS1 exist and are used on occasion. POLS2 provides a standardized construction approval date for all major projects so that they can be fairly compared using subroutine MCOST. POLS3 contains the approval dates for projects as given in the 1975 Task Force Report. The use of this subroutine enables us to check on the accuracy and impact of the endogenously calculated approval dates.

4.3 DEMAND

Subroutine DEMAND takes the separate net energy demand forecasts from POLD1, sums them to obtain total net demand, and adds transmission losses (calculated using a coefficient obtained from regression analysis) to achieve the gross demand that must be supplied by the generating stations. The annual

[37] This study by B.C. Hydro actually has a base case assumption of a real oil price increase of 4.0 percent per year. Many analysts now assume that world oil prices will remain constant in real terms. This paper uses a rate of 2.0 percent but begins with the gas price set at the international border which, in 1976, was several dollars below the BTU equivalent world oil price.

maximum one-hour peak demand is derived by applying the system load factor anticipated by B.C. Hydro (63.5 percent) to the gross demand.

The equations are also designed so that an energy demand shock of a given magnitude can be introduced beginning in a specified year. A separate system load factor for this shock is provided so that the peak demand may be altered to varying degrees.

A final secton of DEMAND introduces various pieces of financial information for use later in the model. They include B.C. Hydro's assumptions about the future rate of inflation and its own interest coverage policy, as well as data on interest payments, sinking fund deficiencies and maturity dates for debt issued prior to 1976.

4.4 SUPPLY

Subroutine SUPPLY represents the heart of this model, generating the financial and engineering information in response to DEMAND which permits us later to perform an economic analysis of marginal costs. There are four primary functions of this subroutine. The first is to provide the data required on each of the possible upstream facilities (generation projects and their associated transmission lines) to perform an economic analysis in MCOST enabling us to rank the projects in APPROVE. Once this analysis has been done, MCOST is bypassed and APPROVE sets project approval dates as dictated by demand forecasts, and the resulting aggregate engineering and financial figures are calculated in SUPPLY.

In order to obtain the necessary detail required for this approach, the production capabilities and investment profiles of over 35 different generation projects are modelled.[38] Once triggered, either by a switch when run with MCOST or by an approval date set in APPROVE, construction expenditures are incurred in each of up to six years in order to bring the project on stream. These expenditures are based on figures contained in working papers behind the 1975 Task Force Report, updated through the application of an adjustment factor specific to each project. This modification converts the estimates into 1976 dollars and incorporates any new real cost changes that may have been recognized.[39]

Upon project completion, two stocks containing additions to various categories of plant in service (hydro-electric, Hat Creek coal, East Kootenay coal and gas turbine) since the start of the simulation period are augmented. The first is measured in 1976 dollars and is simply the sum of the expenditures during construction. It is used later as a base for determining

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[38] In the case of large projects with distinct and divisible generation Units, these Units are treated as separate projects whenever possible.

[39] This approach assumes that the real cost of construction for each project is independent of when it is built within the 15 year framework we are considering. This assumption does not appear unreasonable in light of two conflicting forces at work. The first is an observed tendency for construction costs to rise at a slightly higher rate than general prices. This increase in real construction costs is offset by any technological improvements which might be incorporated in the design of future projects. These are unlikely to be very large in the case of hydro-electric facilities, but may be more significant for thermal projects. A recent study done for B.C. Hydro, however, indicated that improvements in the efficiency of coal-fired facilities are expected to be no more than 10 to 15 percent, and these are still 10 to 15 years in the future.

operating costs. The second stock is measured in historic dollars (obtained by multiplying each year's 1976 dollar expenditure by that year's price index) and includes an endogenously calculated interest during construction. It will serve to help determine depreciation charges under traditional accounting procedures. Increases in the stock of energy capability and of peaking capacity for each category of generating facility are also recorded upon project completion.

This detailed information on each project is then aggregated for all generation facilities. These aggregated variables include investment in generation facilities (both real and nominal), energy generation capability (the entire capability for each category of plant under average and critical water conditions and at year end as well as the average during the year), peaking capacity (the entire capacity for each plant category) and value of plant in service (the stock of each plant category completed after 1975 in both 1976 and historic dollars).

A similar procedure is followed for the more than one dozen separable major transmission projects associated with the various generation facilities. These too are triggered either through a switch coefficient to cost the generation project and its associated transmission facilities in MCOST or through an approval date set in APPROVE. The same tracing of disaggregate and aggregate economic stocks and flows is undertaken, although no engineering information need be maintained in this case.

The second major function of subroutine SUPPLY is to calculate the economic stocks and flows resulting from expansion of downstream facilities. These facilities are divided into the following classifications: major transmission lines not associated with particular generation projects, sub-transmission lines (below 500,000 volts), transformation initiating at the transmission level, transformation initiating at the sub-transmission level, distribution facilities (below 25,000 volts) and miscellaneous electric plant. Unlike the upstream projects, investment in these facilities is assumed to be continuous. In most cases, expansion costs are taken to be a linear function of the one year lagged change in peak demand. The real cost coefficient used is determined on the basis of analysis of past constant dollar expenditures and/or discussion with the appropriate officials about present and expected costs.[40] Investment in distribution facilities has been split between that required to serve new customers (which is taken to be a linear function of the one year lagged change in the number of customers) and that prompted by growth in the peak demands of existing customers. Investment in miscellaneous electric plant, a relatively minor item, is assumed to be a linear function of the one year lagged change in annual energy demand. The investment in each type of facility is accumulated in separate stocks of new plant in service measured in both 1976 and historic dollars.

Still in the system design area, a third responsibility of

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[40] The analysis of expenditures on facilities below the major transmission level can be difficult due to problems in obtaining and allocating the appropriately disaggregated cost information. This problem is largely avoided in this paper by analyzing only the very largest customers (who take electricity at the sub-transmission level) and the very smallest customers (who require, in addition, all the downstream facilities).

SUPPLY is to determine the desired reserve margin of peaking capacity over peak demand. This depends largely on the nature of the generating system with coal-fired units requiring a greater margin than the more dependable hydro-electric facilities. Once the ranking of new projects has been determined, the desired reserve margin is specified as a function of the peaking capacity of various types of generating equipment.

The fourth major task of this subroutine is to determine the quantity and source of energy generated each year. This is achieved by utilizing generating facilities in order of increasing operating costs until gross demand is met. Thus, hydro-electric generating plants first meet demand, followed by coal and then petroleum-fired Units. Any remaining energy deficits are supplied by imports, although the system is designed so that these will not be required (because the demand, in the runs reported here, is assumed to be known six years in advance). Gross demand is that generated in DEMAND plus the available export demand that is economic to serve. B.C. Hydro is assumed to seek to export the difference between total energy capability (under whatever water conditions are specified) and gross firm energy demand whenever the marginal operating costs to society are below the marginal revenue that would be received. A coefficient with a base case value of .5 indicates what proportion of the export market sought is actually attained.

4.5 MCOST

Subroutine MCOST takes the data from SUPPLY and performs an economic analysis of both the cost of the major generation projects with their associated transmission facilities and the cost of each project's separable Units.[41] Each year during a project's life, real operating, depreciation and capital costs are determined. These average annual costs are adjusted upward slightly to transform them to an end of year position and are then accumulated in a stock variable which is compounded forward each year by the real rate of social time preference. Upon the project's termination, this stock is divided by the real social time preference rate raised to a power reflecting the number of years elapsed since 1976. This serves to discount costs back to yield a present value of real costs as viewed from 1976.

Depicted algebraically, each year following project i's approval,

$$KC_{i,t} = KC_{i,t-1} * (1 + STP) + C_{i,t} * (1 + STP)^{.5} \quad .....(1)$$

Upon termination of project i,

$$KCPV_i = KC_{i,t} / (1 + STP)^{n} \quad ....(2)$$

where:

$KC_{i,t}$ is the stock of accumulated real costs associated with project i in year t;

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[41] The Revelstoke project, for example, has six generation Units which can be developed at different times.

STP is the real rate of social time preference (with a base case value of .05);

Ci,t are the real operating, depreciation and capital costs associated with project i in year t;

KCPVi is the discounted present value of all real costs over project i's life;

n is the number of years elapsed since 1976.

In order to be able to compare and rank the different projects, these costs must be divided by a measure of electrical output. We use the incremental energy capability (under average water conditions) for the major projects, and peaking capacity for those which are not designed to generate energy. A similar annual compounding and final discounting procedure to that set out above is followed.

As both the costs and output associated with each complete project depend upon the rate of development of the project's separable Units and their interaction with the system's other generation sources,[42] a base case must be specified. In this paper, we use the rate of development and interdependence of projects recommended in the 1975 Task Force Report. Subroutine POLS2 is used to set a standard initial approval date of 1975 for each major project.

There are three components to the operating costs associated with generation and transmission projects. Following the 1975 Task Force Report, fixed real annual operating costs

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[42] This is particularly true for hydro-electric projects. For example, the effect on net output of a river diversion depends on the generating facilities on both rivers affected by the diversion.

are taken to be a category-specific percentage of the total real capital cost of each project. The only modification to this approach introduced in this paper is the previously described incorporation of real wage increases which results in the increase of this coefficient over time. We also use the figures (updated to 1976 dollars) suggested in the 1975 Report for the non-fuel variable costs in mills per KWH .

We do depart, however, from the Task Force in our selection of some of the variable costs of fuel. The opportunity price of natural gas at the Burrard plant is taken to be $1.83 per thousand cubic feet (Mcf) (18.3 mills per KWH), approximately triple what B.C. Hydro was actually paying in 1976. This is based on a small net upward adjustment, due to transportation costs ,[43] of the export price of $1.80 per Mcf at the Canada-U.S. border near Vancouver, and is equivalent to an oil price of $11.00 a barrel. The estimated average fuel cost at all gas turbine plants is assumed to be 28 mills per KWH.

Hat creek coal is valued at $6.00 per ton, less than one-third more than the revised cost to B.C. Hydro of extracting the coal and paying the provincial royality.[44] This figure is less than 25 percent greater than the Authority's "most likely" opportunity value of the coal, and well below the more than

[43] The distance of the B.C. Hydro gas transmission line from the Westcoast pipeline (the wholesaler) to the Burrard plant is greater than the distance from the B.C. Hydro tap to the Canada-U.S. Border.

[44] This higher coal cost reflects the opportunity cost concept employed in this paper. However, its use may not be unrealistic in light of the possibility that the Province may raise its coal royalty to capture this economic rent. Alternatively, this adjustment could be viewed as incorporating some of the external costs associated with coal use.

$10.00 price that has been suggested by the B.C. Energy Commission (B.C.E.C., 1975). The higher quality East Kootenay open pit coal, about which relatively little is known, is valued at $12.00 per ton, some one-third above the cost of extraction (including royalties at existing rates) used by the 1975 Task Force Report.

Water licence fees are assumed to represent the opportunity cost of the use of the river and are left at the 1976 actual rates.[45] As mentioned earlier, the real price of oil, natural gas and coal is assumed with the result that the petroleum fuels rise at two percent annually to reach a 1976$ oil price equivalent of $14.50 in 1990.

Three types of depreciation charges are used in performing the economic analysis of the various projects. The base case employs the "opportunity life" straight line method using an average expected service life of 40 years. This figure is derived by weighting the expected economic life of different classifications of non-residential capital stock in Canada by their mid-1976 net constant dollar stock.[46] For comparison, we also use the traditional straight line depreciation on the expected life of the project and a 5.7 percent annual charge applied to a declining balance measure of net capital stock. This latter approach is that used in the Bank of Canada's RDX2 model of the Canadian economy and is simply a different

[45] This assumption is clearly not appropriate for all of B.C. Hydro's present and prospective dam sites. However, the Authority's figures suggest that the opportunity cost of the affected rivers is generally relatively small.
[46] This figure was calculated from information contained in Statistics Canada's Fixed Capital Flows and Stocks, 1972-76.

application of the "opportunity life" concept. In all cases, the depreciation charge is applied to the previous year's net capital stock plus new investment measured in real terms. Algebraically,

$$Dt = D * (Kt-1 + It) \quad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3)$$

where:

$Kt = (Kt-1 + It) * (1 - D)$;

Dt is the real depreciation charge in year t;

Kt is the net real capital stock in year t;

It is the real investment in year t;

D is the relevant depreciation rate.

Following the opportunity cost concept, the annual cost of capital consists of two components. The first is the after-tax real supply price of capital to business of 7.5 percent as used in the RDX2 model. The second is the RDX2 average real annual tax return on industrial capital of 3.0 percent. The total of 10.5 percent is applied to the average net stock of capital each year.[47]

The real rate of social time preference is taken to be 5.0 percent, half that generally used by B.C. Hydro. This figure may still be somewhat high, given that the real return on government bonds, a reasonable proxy, has averaged 3 to 4 percent in the past.[48] Sensitivity analysis is performed using real rates of

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[47] This approach is similar to that used in Helliwell et al (1976).

[48] See Campbell (1975).

2.5 and 7.5 percent.

To summarize this explanation of the determination of the real annual costs associated with each project, we present algebraically the components of the Ci,t shown in equation (1).

$$C_{i,t} = A_{i,t} * KG_{i,t} + B_{i,t} * Q_{i,t} + D_{i,t} * (K_{i,t-1} + I_{i,t}) + E * (K_{i,t-1} + K_{i,t})/2 \quad \ldots\ldots (4)$$

where:

Ci,t are the real operating, depreciation and capital costs associated with project i in year t as per equation(1);

Ai,t is the fixed real annual operating cost coefficient for project i in year t;

KGi,t is the accumulated real capital cost of project i in year t (project i's gross real capital stock);

Bi,t is the variable (fuel and non-fuel) annual real operating cost coefficient for project i in year t;

Qi,t is the electrical output (in KWH) of project i in year t;

Di,t is the coefficient reflecting the type of depreciation method being employed on project i in year t;

Ki,t is the net real capital stock associated with project i in year t;

Ii,t is the real investment in project i in year t;

E is the coefficient reflecting the before-tax real supply price of capital (assumed to be .105).

4.6 APPROVE

This subroutine operates in a time horizon six years ahead of the period being simulated and approves new generation and transmission projects when future energy capability and/or peaking capacity is expected to fall short of future energy and/or peak demand. Future gross demand, including any demand shocks, is calculated in subroutine DEMAND using the information obtained in POLD1. Future energy and peaking capacity is determined on the basis of existing and approved generation projects. When a deficiency in either component is forecast, the next least-cost project (based on results obtained from MCOST) that can fill the gap is approved, and supply capability and capacity six years hence are appropriately augmented. The technical criteria used to determine future deficiences are those now in use by B.C. Hydro as explained in Chapter 2. Projects are approved only if the technical, legal and environmental restrictions mentioned in that chapter have been met. Those projects requiring fewer than six construction years are approved in time for them to come on stream in the sixth year. Special consideration is given to the need for gas turbines on Vancouver Island to supply local peak demand because of limitations on underwater transmission capacity.

The subroutine does not fully optimize approval dates on the basis of economic criteria because of the complexity that would be involved.[49] However, the ranking and approval conditions are set so as to recognize and incorporate economic considerations as much as possible. Projects are ranked in order of increasing cost for their complete development. Relatively low cost diversion projects are given priority once they are technically feasible. The inexpensive "middle Units" of major hydro projects are brought on quickly so as to displace existing high cost thermal sources.[50] In short, an attempt is made to approximate the economically optimal timing of new projects subject to the technical criteria that must be met.[51]

4.7 COSTS

This subroutine performs two major functions. The first is to determine annual costs according to traditional accounting procedures. These costs are calculated each year in terms of nominal dollars and are then converted into 1976 dollars and

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[49] In order to determine the optimal economic timing of a new, relatively large project which would displace a current high cost marginal source, one would require information about the expected future growth rate in demand, the rate of development of the different Units of the new project and the variance of several key parameters. Reliance solely on the technical criteria, however, introduces discontinuities in the cost curves as minor quantity changes can have major cost implications. These instabilities would be reduced with a full economic analysis which considered the costs and benefits of proceeding with or deferring a new project.

[50] The initial Units of a large hydro-electric project are expensive because of the high costs associated with reservoir and dam construction. The incremental costs of the "middle Units" are relatively low compared with the additional energy that will be provided. The final Units, however, produce little new energy and thus show higher costs per unit of output.

[51] If required, the approval dates suggested by the model could be manually adjusted to find the precise plan which minimized the present value of costs subject to the satisfaction of all technical criteria.

divided by gross energy production to get real cost per KWH as measured by the accountant.

Fixed operating costs are initially set at their 1975 level and are later increased by applying various price-adjusted coefficients to different categories of new plant in service (as measured in 1976 dollars). Variable operating costs are determined through the application of price-adjusted coefficients to the generating sources actually used.[52] Water licence fees, school taxes, municipal 'grants' and land taxes are calculated using the procedures now in effect in B.C.

Depreciation charges are first set at their 1975 amount and are subsequently augmented by the product of a coefficient representing the inverse of the expected economic life of new projects and the new plant in service (as measured in historic dollars). New bonds are issued to make up the difference between total financial requirements (including sinking fund contributions and shortfalls in repayment of principal at maturity) and what can be generated internally under the new financial policy on desired net income levels. Interest payments are then determined on the basis of these new outstanding bonds as well as the commitments on bonds issued before 1976.

The second function of this subroutine is to perform an economic analysis of the change in costs associated with the demand shock introduced earlier. The analysis follows the same basic procedures as were used in comparing possible projects in

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[52] In order to be consistent with costs used in the economic analysis, and because royalties may be increased to correct the current situation, the opportunity (rather than actual) cost of the various fuels is employed in the accounting section.

MCOST. This time, however, we are interested in the system as a whole, and wish to examine the impact on those costs with a positive opportunity value - all variable and any new fixed charges. We also wish to distinguish between the costs incurred by the smallest and largest customers.

The various generating and downstream facilities are grouped into different categories of relatively homogeneous assets. Fixed operating cost coefficients are applied to each category's post-1975 gross real capital stock while variable operating opportunity cost coefficients are applied, where appropriate, to the total quantity produced by each asset category. Annual depreciation charges are calculated using the economy-wide average rate of 5.7 percent taken on a declining balance measure of post-1975 capital stock. The cost of capital is determined using the before-tax real supply price of 10.5 percent applied to the average net real post-1975 capital stock. By summing across all asset categories the costs associated with the smallest customers are determined while the largest customers require only those categories down to the sub-transmission level.

These costs are compounded forward annually, as are the relevant quantities, to the end of the simulation period and are then discounted back to 1976, again using the real rate of social time preference. A simulation period of 55 years is used in this instance to represent an average life for new facilities brought on stream between 1975 and 1990. By comparing the change in the discounted present value of costs between the base case run and one containing a demand shock, with the corresponding change in the quantity supplied, a marginal cost per unit of output can be attained.

The procedures followed for the economic analysis are highlighted algebraically below.

For each asset category j in each year t,

$$C_{j,t} = A_{j,t} * KG_{j,t} + B_{j,t} * Q_{j,t} + D * (K_{j,t-1} + I_{j,t}) + E * (K_{j,t-1} + K_{j,t})/2 \quad \text{.............................}(5)$$

where:

$C_{j,t}$ are the real operating, depreciation and capital opportunity costs associated with asset category j in year t;

$A_{j,t}$ is the fixed real annual operating cost coefficient for category j in year t;

$KG_{j,t}$ is category j's post-1975 gross real capital stock in year t;

$B_{j,t}$ is the variable (fuel and non-fuel) annual real operating cost coefficient for category j in year t;

$Q_{j,t}$ is the electrical output (in KWH) produced by category j in year t;

D is the depreciation charge coefficient of .057;

$K_{j,t}$ is category j's post-1975 net real capital stock in year t;

$I_{j,t}$ is the real investment in category j in year t;

E is the before-tax real supply price of capital coefficient of .105.

For customer class k,

$$Ck,t = \sum_{j=1}^{x} Cj,t \qquad t = 1,\ldots,55 \ldots\ldots\ldots\ldots(6)$$

where:

x is the number of asset categories required to serve customer class k.

Each year during the simulation period,

$$KCk,t = KCk,t-1 * (1 + STP) + Ck,t * (1 + STP)**.5 \ldots\ldots(7)$$

and

$$KQk,t = KQk,t-1 * (1 + STP) + Qk,t * (1 + STP)**.5 \ldots\ldots(8)$$

where:

KCk,t is the stock of accumulated real costs associated with customer class k in year t;

STP is the real rate of social time preference (with a base case value of .05);

KQk,t is the stock of accumulated gross production associated with supplying customer class k in year t;

Qk,t is the gross production (in KWH) associated with supplying customer class k in year t.

At the end of the simulation period,

$$KCPVk = KCk,t / (1 + STP)**n \quad \text{.........................(9)}$$

and

$$KQPVk = KQk,t / (1 + STP)**n \quad \text{.........................(10)}$$

where:

KCPVk is the discounted present value of all real opportunity costs associated with supplying customer class k during the simulation period;

KQPVk is the discounted present value of all gross production associated with supplying customer class k during the simulation period;

n is the number of years between the end of 1976 and the end of the simulation period (53).

The marginal cost per unit of output for customer class k is

$$(KCPVk,base - KCPVk,shock) / (KQPVk,base - KQPVk,shock) \quad \text{........................(11)}$$

where:

the subscripts base and shock indicate the value of these variables under base case and demand shock conditions, respectively.

4.8 RATES

This subroutine provides an indication of future real and nominal average electricity prices for various customer classes using the information from the conventional accounting section of COSTS. Revenues from residential, general, bulk, private utility and export sales are calculated based on existing and committed average prices and forecast sales. Any anticipated differences between the nominal revenue that will be generated and that required to meet total nominal costs will be eliminated by an adjustment in average prices. This adjustment is the same percentage change for all classes (except for the export price which is held constant in real terms) and assumes a zero demand response to the changed prices.

For the applications chapter of this paper, the model will be extended so as to permit appropriate demand responses to the new marginal prices that will be incorporated in the revised rate structure.

5. THE RESULTS

In this chapter we present the results of computer simulation runs using the model that has just been outlined. The first section reports on the project costing and ranking function; the second forecasts costs using a conventional accounting approach; and the third presents various estimates of marginal economic costs. All three sections provide the results of sensitivity analyses in which key assumptions are altered from those in the base case, as well as attempt an interpretation of the results obtained.

5.1 Project Costing And Ranking

5.1.1 Base Case

The results of the project costing analysis performed in subroutine MCOST are presented in Table 1. Generation projects are grouped according to whether they are being considered primarily for their contribution to energy capability or peaking capacity. They are ranked within each category in the order of in-service dates as proposed in the 1975 Task Force Report. These dates indicate when existing technical, legal, environmental and/or social constraints are expected to be overcome. With the exception of the Hat Creek and East Kootenay coal-fired plants and the gas turbines proposed for Vancouver Island, all projects are hydro-electric.

Three key assumptions used in generating the base case results are that real capital costs exceed present estimates by

TABLE 1

COSTING OF GENERATION PROJECTS

ENERGY PROJECTS	(1) UNIT NO.	(2) EARLIEST POSSIBLE IN-SERVICE DATE	(3) AVERAGE ENERGY CAPABILITY (MM KWH)	(4) PEAKING CAPACITY (M W)	(5) BASE CASE (MILLS/KWH) (1976 $)	(6) CAPITAL COST: NO COST OVERRUN	(7) CAPITAL COST: 50% COST OVERRUN	(8) STP: 2.5%	(9) STP: 7.5%	(10) DEPRECIATION: CONVENTIONAL STRAIGHT LINE	(11) DEPRECIATION: DECLINING BALANCE METHOD
SITE ONE (now under const.)	1-4	1979	3150	700	13	11	16	11	16	15	13
REVELSTOKE	1-6	1981	7970	2700	14	12	17	11	17	16	14
HAT CREEK I	1-4	1982	13,680	2000	19	17	21	19	20	19	19
KOOTENAY DIVERSION	1	1984	875	-	2	2	3	2	3	2	2
MCGREGOR DIVERSION (assumes Site C)	1	1985	3828	-	7	6	8	6	8	8	7
HAT CREEK II	5-8	1985	19,160	2800	18	16	20	18	18	18	18
EAST KOOTENAY	1-2	1983	9580	1400	17	16	18	17	17	17	17
SITE C (without McGregor Div.)	1-4	1984	4290	900	19	16	22	15	22	21	19
CAPACITY PROJECTS					($/KW)						
VANCOUVER ISLAND GAS TURBINES	1-2		1314	300	206	201	212	214	199	206	204
G.M. SHRUM	10		-	275	10	8	12	8	12	11	10
MICA	5		-	400	7	6	8	6	8	8	7
MICA	6		-	400	7	6	8	6	8	7	7
REVELSTOKE	5		-	450	11	9	13	9	12	12	10
REVELSTOKE	6		-	450	10	8	12	8	11	11	10
SEVEN MILE	4		75	175	15	12	18	12	17	16	14

25 percent, that the real rate of social time preference is 5.0 percent and that the straight line "opportunity life" depreciation method is the appropriate technique to use. To put the numbers in the table in perspective, the operating cost of the Burrard thermal plant (with natural gas priced at its opportunity value) is 19 mills per KWH. The similarity in cost between the Site C hydro project and the Hat Creek coal-fired plant should be noted at this stage.

A further analysis under base case assumptions was performed on the costs associated with the separable Units comprising each major generation project. As would be expected, these costs per unit of output initially fall and then often turn upwards as the project is more fully developed. Thus for the Revelstoke project with its fully developed costs of 14 mills per KWH, Units 1 and 2 together show a cost of 16 mills while Units 3 and 4, based on the incremental costs and production that each is responsible for, are costed at 3 and 8 mills respectively. Units 5 and 6 add only to peaking capacity. This information is later used to suggest the appropriate rate of development of each project.

We turn now to examine the impact on absolute and relative per unit economic cost resulting from a change in each of the three key assumptions listed in the last paragraph.

5.1.2 Sensitivity Analysis

Columns 6 and 7 of Table 1 reveal the results of "across the board" capital cost adjustments of zero and fifty percent respectively.[53] The changes will affect fixed operating costs (which are determined by applying a coefficient to each project's capital cost) but will leave unchanged variable operating costs. It is not surprising then that these variations have a strong impact on the unit costs of all projects, although the effect is smaller with the coal-fired projects. Indeed this differential impact is critical in determining whether the Site C project should proceed before a plant at Hat Creek.

The next columns indicate the impact of varying the real rate of social time preference (STP) from 5.0 percent to 2.5 and 7.5 percent. A higher STP rate implies a greater discounting of the future relative to the present. Because of the declining real costs over time charged to each project, a higher STP rate will cause a greater reduction in the present value of the quantity produced (which is assumed to be constant through the project's life) than in the costs of production. This will lead to higher discounted unit costs. The opposite applies in the case of a reduced STP rate. We again see the differential impact of these changes, with the capital intensive hydro projects being the more sensitive to this variation. The ranking of the Site C and Hat Creek projects is even more dependent on this variable than on the capital cost assumption.

The final columns in Table 1 show the effect of the different depreciation procedures discussed in the last chapter.

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[53] A better approach would be to choose possible capital cost variations on the basis of present knowledge and experience for each project. Thus the capital cost estimate of a relatively standard design hydro project on a well surveyed site would likely be more accurate than that of the first coal-fired plant ever to be built by B.C. Hydro.

Standard straight line depreciation based on the asset's expected life yields a higher unit cost for projects with a life greater than the economy-wide average (such as hydro-electric facilities). Although the annual depreciation charges are lower under the conventional method for the long-lived assets, the cost of capital is higher since it is applied to a net stock which is not declining as quickly as under the "opportunity life" approach. In the early years the lower depreciation charges dominate. Later, however, the higher cost of capital overwhelms this component and leads to higher total costs over the project's operating life. Thus the ranking of Site C and Hat Creek is also dependent on the type of depreciation policy employed. The similarity in unit cost for the thermal projects under the two depreciation procedures results from the fact that these projects have an expected life close to that of the economy-wide average life.

The use of the economy-wide annual depreciation rate of 5.7 percent applied to a declining balance measure of capital stock gives remarkably similar unit costs to those generated by the "opportunity life" straight line depreciation method. The higher total costs associated with this method in the early years are almost exactly balanced by lower costs in later years. This similarity will prove helpful, since we will later use this method in subroutine COSTS because of the difficulties inherent in keeping track of terminating dates for a variety of different projects.

Although not shown on Table 1, a sensitivity analysis of the impact of different assumptions about fuel costs was also performed. If the cost of coal is taken to be the anticipated extraction costs plus today's royalty rates (rather than the opportunity cost used in the base case), unit costs for the three coal projects shown fall by 2 mills per KWH. This makes these thermal plants a clear favourite over the Site C hydro facility.

5.1.3 Project Ranking

A first glance at the energy projects listed in Table 1 might suggest a substantial variation between the ranking suggested by the base case results and that adopted by B.C. Hydro. However, with the exception of the East Kootenay thermal plant, this apparent difference is illusory. The two diversion schemes, with their unusually low costs, are scheduled by B.C. Hydro to begin operation at the earliest possible in-service date. Hat Creek II must await the development of Hat Creek I before it can proceed.

In the case of the East Kootenay coal plant, this project has two important detractions not reflected in the economic analysis. The first concerns its distance from the major load centres, with important implications for the stability and reliability of the transmission system. The second centres around access to the coal. B.C. Hydro does not now hold mining rights to coal in the area and, as a result has not proceeded very far in its analysis of this option.

For these reasons, the project ordering that is adopted in subroutine APPROVE is the same as that recommended by B.C. Hydro in its 1975 Task Force Report. Site C is assumed to come on stream after East Kootenay coal if additional generating capacity is required.[54] Energy from the small and inexpensive Kootenay River Diversion is programmed to be available in 1984 regardless of the supply-demand balance of the time. The McGregor Diversion and the "middle Units" of the Revelstoke and Site C hydro projects are slated to be operational as soon as possible, subject to there being a forecast need for new generating facilities.

The base case unit costs for the capacity projects also call for some explanation. The gas turbines on Vancouver Island are required because of anticipated limitations on the capacity of the transmission lines carrying power to this electricity-deficient area. The high unit cost figure shown in Table 1 results from the assumed capacity factor of 50 percent.[55] A lower capacity factor would reduce this figure substantially, although it would never fall below that of any of the hydro peaking projects. The tenth Unit at the Shrum plant on the Peace River, while not producing additional energy, can be used to displace more costly Units now performing this role, thereby providing a saving which does not appear in our analysis.

Thus for peaking projects, we can again rank the various options in a manner consistent with that adopted by B.C. Hydro

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[54] This is consistent with the base case ranking in our analysis. However, as has been noted, the optimal positioning of Site C relative to the thermal projects is sensitive to alterations in several key assumptions. There is some indication (based on private discussions and statements in the media) that Site C is now becoming relatively more attractive in the eyes of B.C. Hydro. It did not figure in the 1975-1990 Plan proposed by the 1975 Task Force Report.

[55] Capacity factor is the ratio of the average load on a machine for the period of time considered, to the capacity rating of the machine.

in 1975. The Vancouver Island gas turbines are brought on when the demand facing the total system reaches a specified level.[56] The remaining projects are triggered as required to meet a forecast capacity deficit, in the order in which they are listed in Table 1.

5.2 Conventional Accounting Projections

5.2.1 Base Case

This section forecasts key financial variables based upon accounting conventions consistent with those now employed by B.C. Hydro. The electrical demand growth rate is that specified in the 1975 Task Force Report, as are the basic cost data and the following exogenous assumptions. The inflation rate is 15 percent in 1975, 10 percent between 1976-1979 and 5 percent thereafter. The nominal effective interest rate on new bonds is 10 percent throughout the 1975-1990 period.[57]

Other key assumptions are that the projects are initiated according to subroutine APPROVE, that water conditions are average and that fuel is priced at its opportunity value. In the next section we will relax each of these assumptions and examine

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[56] We assume that the regional balance of electrical demand will hold the pattern suggested by B.C. Hydro in the Task Force Report. This implies that the demand on the Island will be at the level requiring gas turbines when the provincial demand is at the level which triggered the turbines in the 1975 Report.

[57] The failure by B.C. Hydro to link inflation and nominal interest rates could prove to be a problem. However, over the 1975-1990 period, the rate of inflation averages an annual compound rate of 6.4 percent which is not inconsistent with a 10 percent nominal rate on low risk bonds.

the resulting impact.

Table 2 summarizes some of the projections under these assumptions. 'Energy Generated' consists of gross demand in B.C. Hydro's service area plus any exports that are both economically attractive to the Authority and demanded by those outside the province (under the 50 percent of export potential assumption). 'Investment' is calculated by summing the real capital expenditures required to meed demand growth and converting these into nominal dollars through the price level index.[58] 'Gross Debt' is the sum of bonds issued prior to 1976 that will still be outstanding each year plus the new debt required to meet capital and financial requirements in excess of what can be generated internally under the new net income policy. 'Annual Costs' comprise fixed and operating costs, all local and water taxes, depreciation and net interest charges and any net income. They are also expressed in nominal terms. The final column, 'Cost per KWH' is simply total annual costs (now converted to 1976$) divided by the energy generated.

5.2.2 Sensitivity Analysis

In order to appreciate the importance of several key assumptions, we examine the impact on the average real cost per KWH over this period when these assumptions are altered. The results are reported in Table 3.

We first disengage subroutine APPROVE and explicitly read

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[58] It is interesting to note that the 1976-1981 investment shown here totals within 4 percent of that projected in a November 1976 Prospectus by the Authority (1976b,18). In fact, their figures are higher than those shown in this Table.

TABLE 2

1976-1990 PROJECTION OF KEY FINANCIAL VARIABLES

YEAR	ENERGY GENERATED (MM KWH/YR)	INVESTMENT (MM NOMINAL $/YR)	GROSS DEBT (MM HISTORIC $)	ANNUAL COSTS (MM NOMINAL $)	COST PER KWH (1976 $) (MILLS/KWH)
1976	25,102	526	3932	463	18
1977	28,402	542	4340	535	17
1978	31,544	702	4960	624	16
1979	35,321	983	5883	800	17
1980	39,097	1181	6981	990	17
1981	43,095	1019	7834	1120	17
1982	47,427	1123	8721	1413	18
1983	52,092	1133	9629	1600	18
1984	56,868	1125	10,458	1925	19
1985	61,866	1344	11,463	2191	19
1986	67,198	1428	12,488	2457	19
1987	72,973	1603	13,674	2879	19
1988	78,860	1729	14,885	3226	19
1989	84,858	1790	16,208	3775	20
1990	91,189	1400	17,053	4144	19

in the appropriate approval dates for major projects as given in the 1975 Task Force Report. Average cost per KWH during the 1976-1990 period falls from 18.1 to 17.9 mills. There are two reasons for this reduction. The first is that the approval dates in the Task Force for new peaking projects are too late to prevent the loss of load probability from rising above its desired maximum in three different years. Subroutine APPROVE, on the other hand, follows the stated reliability criterion and approves four of these peaking projects a year earlier than does the Task Force. The second reason concerns the fine tuning done in the Task Force which enables optimal economic timing of new projects. Because of the relatively high cost of running Burrard, several coal-fired Units are brought on earlier in the Task Force than are required from a technical perspective, thereby displacing gas-fired energy. Subroutine APPROVE also initiates Site C for commencement in 1990 while the Task Force shows a very slim energy margin in 1990 (the terminal year) and thus never builds this project.

TABLE 3
SENSITIVITY ANALYSIS
ON THE AVERAGE COST/KWH
IN THE 1976-1990 PERIOD

	1976 $ MILLS/KWH
BASE CASE	18.1
TASK FORCE APPROVAL DATES	17.9
CRITICAL WATER CONDITIONS	20.4
ACTUAL FUEL PRICES	17.3

Despite these differences, the Task Force plan effects a saving of only one percent in average unit costs over this period. Two-thirds of the generation projects (16) are approved at the same time under both runs. Seven others differ only by one year, while one project has a two year difference.

Another variation on the base case results from changing the assumption about water conditions. Table 3 shows that under critical conditions (the driest five years in recorded history), average cost rises from 18.1 to 20.4 mills per KWH. Project approval dates do not change since planning is done on the basis of critical conditions. However, less water means more use of expensive thermal facilities. Under these conditions, the Burrard plant operates at capacity in most years and the expensive gas turbines are also required to produce energy. Hence the 13 percent increase in average cost during this period.

The final assumption to be altered is that of fuel prices. If natural gas and coal are priced at their estimated 1976 cost (rather than their opportunity value), average costs fall from 18.1 to 17.3 mills per KWH. This drop would be more noticeable during critical water conditions when the thermal plants are relied upon more heavily.

5.2.3 Interpretation

Having established the basic stability of the average cost per KWH over the 1976-1990 period to several important variations in the underlying assumptions, we turn now to examine in more detail the relative changes in the component costs. Table 4 summarizes the increases in the base case quantity and costs between 1976 and 1990. Column 4 presents the changes in various categories of real costs during this period, while the final column shows these changes relative to the change in the number of kilowatt-hours.

Looking first at the annual operating costs, we see a sharp increase in variable costs (mainly fuel) which is consistent with the swing toward thermal generation facilities. School taxes show a relatively moderate increase reflecting an assumption about a greater share of the Authority's facilities

TABLE 4

RELATIVE COST CHANGES: 1976-1990

	(1) 1976 (MM$)	(2) 1990 (NOMINAL MM$)	(3) 1990 (1976 MM $)	(4) 1990 COSTS (76$) / 1976 COSTS (76$) (3)/(1)	(5) COST CHANGE RELATIVE TO QUANTITY CHANGE (4)/3.6
CAPITAL CHARGES					
NET INTEREST	214	1262	530	2.5	.69
DEPRECIATION	72	506	213	3.0	.83
NET INCOME	0	379	159	-	-
OPERATING CHARGES					
VARIABLE	18.7	835	351	18.8	5.2
FIXED	123	823	346	2.8	.78
SCHOOL TAXES	21.2	253	106	5.0	1.4
GRANTS & LAND TAXES	4.4	39.4	16.5	3.7	1.0
WATER FEES	9	48	20	2.2	.61
TOTAL COSTS	463	4145	1741	3.8	1.1
PRODUCTION (MM KWH)	25,102	91,109	-	3.6	1.0

being subject to this levy in the future. Municipal 'grants' and land taxes increase in real terms at the same rate as production. Water licence fees, as would be expected, show a reduction in their relative share of costs.

The moderate reduction (in relative terms) of fixed operating costs deserves some comment. These costs consist of fixed operating, maintenance, administration and general expenses plus insurance and interim replacement expenditures. They are determined by adding to the 1975 level of fixed operating costs those new costs associated with additional facilities. This latter figure is determined by applying a coefficient to the real capital cost of the various types of new facilities. This coefficient increases over time to reflect real labour cost changes. The move towards less capital-intensive generation plants is more than offset by the much greater fixed operating costs associated with these facilities. These two factors would tend to increase the relative share of these costs, assuming the basic mix of the system between the various types of non-generating facilities remained approximately constant.

The relative reduction that results from using the figures contained in the Task Force Report (and subsequent interviews) suggests the evolution of technology towards that requiring relatively fewer of these factors (in an economic sense). Alternatively, it could signal the existence of currently unexploited economies of scale which will be realized with the anticipated expansion.[59]

On balance, annual operating costs show an increase in real terms compared to the change in output. Capital charges, on the other hand, exhibit the opposite trend. The depreciation charge consists of the amount that was levied on facilities in 1975 plus the inverse of the expected life of new facilities applied to the historic dollar cost of these facilities. Depreciation on the equipment in service in 1975 remains constant in nominal terms, leading to a sharp decline in real terms over the period under examination. Similarly, the annual charge on facilities being placed in service prior to 1990 will also decline in real terms. Contributing to this trend is the fact that the new thermal generating plant requires less initial capital per KWH generated, a fact which slightly more than offsets its reduced service life and hence higher rate of depreciation.

Net interest charges, the largest component of annual total costs, drop fairly substantially relative to the increase in output during this period. These charges consist of interest on the debt issued prior to 1976 that will still be outstanding each year plus gross interest on post-75 debt less interest during construction. Some two-thirds of the pre-1976 debt will remain outstanding in 1990, and the interest payments thereon, while remaining constant in nominal terms, will fall rapidly in real dollars during this period.

Interest charges on the debt issued subsequent to 1975

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[59] On the other hand, it could indicate an underestimation of these coefficients or an overestimation by the author of the fixed costs (relative to the variable costs) in the initial year of the simulation.

depends on the quantity of such debt and the associated interest rate. In the period 1976-1990, gross outstanding debt increases only 1.8 times in real terms (see Table 2). This relatively moderate increase results from several factors. New generating projects are less capital-intensive and unexploited economies of scale in downstream facilities could result in proportionally less capital spending in the future. More funds are generated internally through net income or profits. And the measurement of outstanding debt in historic dollars leads to its continual decline in real terms during a period of inflation.

This last consideration is somewhat offset by the fact that interest rates incorporate an expectation about inflation. The inflation premium contained in nominal interest rates is reflected in an increase of net interest payments relative to gross outstanding debt of from 5.4 percent in 1976 to 7.4 percent in 1990. The net effect of these conflicting forces is a relative reduction in real net interest charges over this period.

As indicated in Table 2, our model using conventional accounting techniques indicates an essentially stable pattern in real costs per KWH between 1976 and 1990.[60] This result is consistent with B.C. Hydro's own forecasting and is the justification for their long term goal of flattening the rate structure. This section of the paper has indicated the distortions inherent in this accounting framework during periods

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[60] This result is clearly dependent upon assumptions about the rate of inflation. If the figures used in this paper turn out to overestimate future general price level increases, then real costs will rise more quickly than indicated.

of inflation. An earlier chapter pointed out other fundamental weaknesses in using this methodology as a sole basis for establishing a rate structure. We turn now to look at the results of the approach designed to determine the marginal economic costs of the B.C. Hydro system.

5.3 Determination Of Marginal Cost

5.3.1 Base Case

In this section we present the results of an economic analysis of the impact on costs of various demand shocks. In order to isolate the cost effect of changes in peak as distinct from energy demand, two runs are performed for a given energy shock. One run assumes that the shock has an impact on the system's off-peak periods only and does not alter B.C. Hydro's annual peak demand. The other assumes that the change has a load factor identical to that of the system's average, thus affecting both peak and off-peak demand. The cost differential between the two runs is attributable solely to the change in peak demand. The model also distinguishes between the cost changes for the large customers taking power at the sub-transmission level and the smallest customers who also require the full distribution system.

Because of the discontinuities likely as a result of the mechanical project approval process used in this model, a variety of long-term demand shocks are tested. They range from 10 million KWH a year (.04 percent of present energy demand) to

5 billion KWH annually (19.9 percent) for both an increase and decrease in demand. In the short run, these demand shocks are accommodated by varying the amount that each facility is used. In the longer term, the investment programme is adjusted to best fit the new demand projections.[61]

The standard assumptions outlined in the previous base case simulations continue in effect. This includes the assumption that one-half of the export market that is economically attractive for B.C. Hydro to serve is actually available. We also assume that the demand shock introduced in 1976 continues at the same fixed level for the duration of the simulation period. The demand shock does not consist of any changes in the number of electrical customers served by B.C. Hydro. This is assumed to grow at the rate indicated in the 1975 Task Force Report. In the next section, we review the impact of altering these assumptions.

Table 5 presents the results of the introduction of various demand shocks. The first column indicates the size, direction and system load factor of the perturbation. The next two show the discounted present value of the energy and peak generation over the 55 year simulation period relative to that without the demand shock. Columns 4 and 5 present the increase or decrease in the discounted present value (in 1976 dollars) to the largest and smallest customers over this period resulting from the changes in demand.

The final four columns convert this information into 1976

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[61] If demand rises above the Task Force's forecast 1990 level, Site C is used to meet energy deficits while new gas turbines supply any peaking shortage.

TABLE 5

MARGINAL ECONOMIC COSTS FOR VARIOUS DEMAND SHOCKS

DEMAND SHOCK (MM KWH)	SYSTEM LOAD FACTOR OF SHOCK	P.V. ENERGY GENERATED (MM KWH)	P.V. PEAK GENERATED (M W)	P.V. LARGE CUSTOMER COSTS (MM 76$)	P.V. SMALL CUSTOMER COSTS (MM 76$)	LARGE CUSTOMERS ENERGY COST 76$ MILLS/KWH)	LARGE CUSTOMERS CAPACITY COST (76$ MILLS/KWH)	SMALL CUSTOMERS ENERGY COST (76$ MILLS/KWH)	SMALL CUSTOMERS CAPACITY COST (76$ MILLS/KWH)
BASE CASE		1,393,223.0	249335.1	16699.2	20738.7				
-10	63.5%	-198.0	-39.4	-4.2	-4.7	19.7	1.5	20.7	3.0
-10	off-peak	-198.0	0.0	-3.9	-4.1				
-100	63.5%	-5255.0	-397.5	-585.4	-589.8	110.2	1.2	110.6	1.6
-100	off-peak	-5129.0	0.0	-565.1	-567.4				
-1000	63.5%	-27,114.0	-3986.8	-727.5	-771.8	21.3	5.5	22.1	6.4
-1000	off-peak	-27,114.0	0.0	-577.6	-599.2				
-3000	63.5%	-67,750.0	-11,963.1	-1851.3	-1984.1	22.6	4.7	23.5	5.8
-3000	off-peak	-67,750.0	0.0	-1530.2	-1595.1				
-5000	63.5%	-107,422.0	-19,941.8	-2441.5	-2662.9	19.2	3.5	20.2	4.6
-5000	off-peak	-107,422.0	0.0	-2060.5	-2168.7				
+10	63.5%	195.0	42.2	4.2	4.7	20.0	1.5	21.0	3.1
+10	off-peak	195.0	0.0	3.9	4.1				
+100	63.5%	1979.0	400.5	42.3	46.7	19.6	1.8	20.6	3.0
+100	off-peak	1979.0	0.0	38.7	40.8				
+1000	63,5%	16,994.0	3989.5	-165.7	-121.5	13.9	4.1	12.6	5.5
+1000	off-peak	16,994.0	0.0	-236.2	-214.6				
+3000	63.5%	60,795.0	11,965.5	1206.9	1339.6	17.2	2.5	18.3	3.8
+3000	off-peak	60,671.0	0.0	1046.1	1111.0				
+5000	63.5%	101,668.0	19,945.6	2060.8	2282.1	15.5	4.8	16.5	6.9
+5000	off-peak	101,668.0	0.0	1572.0	1680.1				
AVERAGE:						19.4	3.2	20.3	4.6
						22.6		24.9	

AVERAGE MARGINAL ENERGY AND CAPACITY COST FOR ENTIRE SYSTEM: 23.7

mills per KWH. Column 6 is obtained by dividing the results of column 4 by those in column 2 for the off-peak shock. Column 7 is derived by taking the incremental cost in column 4 resulting from the on-peak shock and dividing it by the quantity in column 2. The result is the cost attributable to the change in peak demand expressed in mills per KWH under an assumed load factor of 63.5 percent. The last two columns perform a similar calculation for the small customer using the cost figures shown in column 5.

The results shown in Table 5 merit some comment. Generally, the change in the quantity of energy generated is independent of the load factor of the demand shock. For two of the demand changes, however, there are small differences caused by altering the load factor assumption. A closer examination of the workings of the model reveal that the different peak demands trigger projects designed primarily to supply capacity but which also have an energy component. This new energy capability is then either exported or is included in the energy calculations, thereby delaying the start of new energy projects.

The results generated in the last four columns show considerable consistency with two notable exceptions. Upon closer examination, these anomalies appear to result from the lack of fine tuning inherent in this model and the distortions caused by using a cut off date for demand growth. The basic problem concerns the role of Site C which, under the base case, is triggered for commencement in 1990 to meet a small forecast energy deficiency. As 1990 represents the last year of demand growth, this new project operates far below its energy capability, a situation only partly mitigated under the assumed export market conditions. Thus, in the case of the demand shock of -100 million KWH, this project is no longer required and large cost savings are experienced relative to the reduction in the quantity of energy generated. Hence the artifically large savings in mills per KWH shown to result from this reduction. In the case of the 1000 million KWH shock, thermal projects are accelerated with the result that in 1990 Site C is not required and is never triggered. This is reflected in the cost reduction resulting from the demand increase.

The figures at the bottom of the table for the last four columns represent the mean of the observations in the column. The results of the two anomalous runs just discussed are not included in this averaging. The use of a variety of sizes and directions of demand shocks should minimize distortions caused by the arbitrary decision rules followed in the model. The average figures shown in columns 7 and 9 for the capacity cost, assuming a 63.5 percent load factor, are approximately equal to $18.00 and $26.00 per kilowatt, respectively.

5.3.2 Sensitivity Analysis

In order to understand the sensitivity of these results to variations in some of the underlying assumptions, several alternative simulations were performed. These alternatives introduced demand shocks of 10, 1000 and 5000 million KWH in both directions under an assumed load factor coinciding with the 63.5 percent projected for the system. As such, the results can be compared with the combined energy and capacity average marginal cost of 22.6 mills per KWH for large customers.

We first alter the fraction of the economically attractive export market available to B.C. Hydro from 50 to 100 percent. This enables a smoother reaction to the demand shocks by allowing the export market to absorb more of the difference. The resulting average marginal cost for the large customers becomes 23.6 mills per KWH under this assumption.

We next alter the timing of the demand shock. By delaying the introduction of the permanent change from 1976 to 1980, the average marginal cost rises slightly from 22.6 to 22.9 mills per KWH. The introduction of the shock for only the year 1976 yields a short-term average marginal cost of 20.7 mills. The amount of energy projected for generation in the Burrard plant that year was approximately 1000 million KWH, as compared with its annual energy capability of 5520 million KWH. The large 1976 shock of 5000 million KWH resulted in an average marginal cost of 23.8 mills per KWH, reflecting the need to begin generating energy from the costly gas turbines. Conversely, the 1976 shock of -5000 million KWH led only to an average marginal cost of 16.5 mills per KWH because of the minimal savings possible through reduction in the amount of hydro-electric generated energy.

Finally, we examine the impact on costs of altering the number of small new customers assumed to be served by B.C. Hydro. The results in Table 5 show the unit cost of changes in forecasted energy and/or peak demand for two customer classes assuming no change in the forecast number of customers connected to the system. We now introduce a shock which, beginning in 1976, permanently alters by a fixed increment the number of small connected customers without affecting the electrical demand forecasts. The initial connection charges plus subsequent annual service costs indicate an approximate average annual cost associated with connecting a new small customer of $60.00.[62]

5.3.3 Interpretation

We turn now to an interpretation of the results in Table 5 and a comparison of them with the figures generated earlier in this chapter. From the outset, it is important to recognize that the numbers shown are not to be taken as accurate to the final decimal point, but rather represent an approximation of the relevant marginal economic costs.

Perhaps the most interesting result revealed in Table 5 is the heavy predominance of the energy over the peak demand component of marginal costs. For the large customers, over 85 percent of the incremental costs associated with a long-term electrical demand change (corresponding to the system's load factor of 63.5 percent) are associated with the change in the energy component of the load. This is consistent with the fact that for the energy-critical B.C. Hydro system, a change in the energy demand is first met by altering the quantity of fuel used at the Burrard plant and then by varying the starting dates of major generation and transmission projects.

Changes in peak demand, on the other hand, do not immediately affect the generation planning programme due to the existence of excess reserve capacity, although a permanent

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[62] This figure should be viewed with considerable caution as there is an inadequate amount of publicly available data to estimate these costs with much confidence.

alteration will eventually influence the timing of new capacity-only projects. These, however, are relatively inexpensive, require no new associated transmission facilities, and must be discounted when viewed from 1976. Immediate responses will be felt in the investment on the major transmission, sub-transmission and transformation facilities, but these are small compared with the major generation and associated transmission line expenses.[63]

Another interesting result of this analysis is the proximity of the incremental costs associated with demand shocks emanating from the largest and smallest customers. In the case of a change in energy demand, the similarity results from the fact that either source of change will require the same adjustment in the generation and associated transmission line programme. The only reason for the slight difference in this category between the two customer classes is the assumption that investment in "miscellaneous electric plant" is energy responsive and is twice that for small customers as for large. The relatively greater costs associated with changes in the coincident peak demand of the smaller customers reflects the additional adjustment in downstream transformation and distribution facilities that would be entailed.

The results of the marginal cost analysis would also appear to be quite consistent with those of Table 1 reporting on the economic costs of various generation projects. After removing

[63] The suggested 15-85 demand-energy split for large customers in the _energy_ critical B.C. Hydro system appears consistent with the finding that the relevant demand-energy split for large customers in the _capacity_ critical Ontario Hydro system should be changed from 50-50 to 35-65. (Ontario Hydro, 1976, Vol. I, 17)

the costs associated with "miscellaneous investment plant", the analysis in this section indicates an average marginal energy cost for all customers of 18.5 mills per KWH. This compares with a short run marginal energy cost of 18.7 mills from generating energy at Burrard. In the longer run, disregarding the diversion projects,[64] Revelstoke energy is to cost 14 mills per KWH while all subsequent energy producing projects will cost 17-19 mills.

The capacity related component of costs also seems reasonable. Table 1 suggests the costs of peaking projects (excluding gas turbines) are between $7.00 and $15.00 a kilowatt. This compares with the marginal cost estimates of $18.00 and $26.00 for large and small customers respectively. The difference is accounted for by the additional peak-related costs associated with the relevant downstream transmission, transformation and distribution facilities.

Lastly, we compare the average accounting costs of Table 2 with the marginal economic costs of Table 5. The former increase from 18 to 19 mills per KWH in the period 1976-1990, while the latter average 24 mills for the system as a whole. The purpose, methodology and assumptions underlying the derivation of these two results is quite different and there is no 'a priori' reason why the numbers should be similar. Nevertheless, there is some reason to believe that the two figures are, in fact, reasonably consistent.

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[64] The diversion projects should not be considered as marginal sources of energy. They are relatively small and low cost, and are now being constrained by non-economic considerations. These projects are likely to be brought on stream as soon as institutionally possible, and at least in the case of the Kootenay River Diversion, regardless of the energy supply-demand balance.

The Table 2 results are average, not marginal, accounting costs expressed in 1976 mills per KWH. The existence of a slight increase in these average costs during this period suggests that marginal accounting costs exceed average accounting costs. This slight increase is in spite of the construction of several relatively inexpensive "non-marginal" diversion projects which tend to lower average costs. It is also in spite of the tendency for the average accounting cost of the older capital-intensive projects to fall in real terms during periods of inflation, suggesting further that the real unit cost of new projects must be above average accounting costs.

We conclude this section by noting that the marginal economic costs presented in Table 5 seem consistent with an intuitive understanding of the operation of the B.C. Hydro system, the economic costing of possible new generation projects shown in Table 1, and the average system accounting costs calculated in the previous section. We now turn our attention to the application and implications of these marginal costs.

6. APPLICATIONS

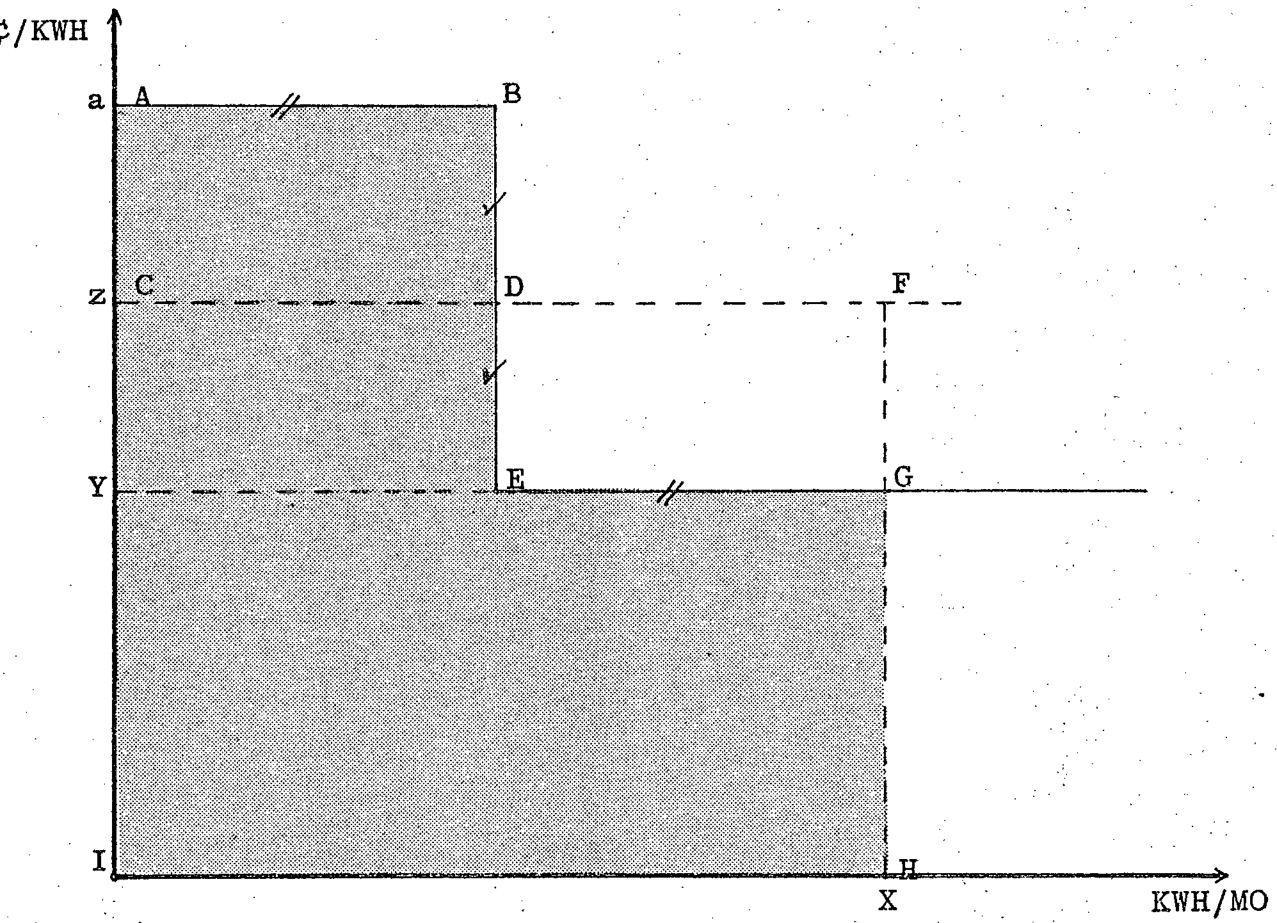
In this chapter, we apply the marginal economic costs derived in Chapter 5 and study the implications for the B.C. Hydro system of this change. The first section discusses the application of economic principles to the design of a rate stucture - both in general and as it could apply to B.C. Hydro. The second explains how the impact on system expansion and costs of a reformed rate structure can be determined, and presents various results from such a restructuring.

6.1 Rate Structure Design

6.1.1 General

The fundamental objective in designing an economically-efficient rate structure is to equate marginal economic price and cost, while keeping average accounting price equal to average accounting cost. Figure 1 represents a typical residential rate structure. A customer consuming x kilowatt-hours per month faces a marginal rate of y cents per KWH and pays a total bill indicated by the shaded "L" which is assumed to equal the accounting costs incurred to serve him. If the marginal economic cost is found to be z cents per KWH, then the marginal rate should be set equal to this and the rate structure designed to ensure that the area beneath the rate curve (revenue) equals the shaded "L". In this simple example, a flat

FIGURE 1



rate of z cents per KWH for all consumption would satisfy both conditions since ABCD=DEFG which implies ABEGHI=CFHI. The difficulty arises when these two criteria are not as easily reconciled. Those who hold firm to the economic efficiency criterion tend to support either a multi-part or multi-block approach. The former adjusts the least price sensitive component of the total bill (usually the customer or fixed charge) so as to meet the revenue objective. The latter modifies the "intra-marginal" consumption rate (a cents per KWH in Figure 1), within the bounds of the customer's consumer surplus, to again meet the accounting condition.

Others abandon the strict economic efficiency objective, allowing the marginal price to deviate from the marginal economic cost. This may be done on the basis of the "inverse elasticity rule" whereby the amount of the deviation is inversely proportional to the price elasticity. Alternatively, a straight "across the board" adjustment in marginal prices so as to be consistent with the revenue requirement is sometimes recommended.

We turn now to examine the specific case of B.C. Hydro and to suggest factors to be incorporated in an optimal rate structure. We shall seek not to deviate from the strict equating of marginal economic costs and prices in our attempt to satisfy the fundamental objective outlined at the outset.

6.1.2 B.C. Hydro

In suggesting an appropriate rate structure, we shall use the marginal economic costs calculated in the last chapter.

Average existing prices in each customer class will be taken to represent the appropriate average accounting costs.[65]

Residential customers as a class have a coincident load factor of between 45 and 50 percent and are billed on the basis of the amount of energy they use each period.[66] In order to use the figures shown in Table 5, we must adjust upwards the 4.6 mills per KWH capacity charge for small customers to reflect this reduced load factor. The resulting combined energy and capacity marginal economic cost is 26 mills per KWH. This compares with an average accounting cost of 28 mills per KWH.

This suggests that the appropriate rate structure would be a flat rate of 2.6 cents per KWH for all units of energy consumed. The additional .2 cents per KWH could be obtained through a small customer charge.[67] This is in contrast to the existing high priced initial block followed by a 1977 marginal rate of 1.8 cents per KWH (in 1976$).

Bulk customers, on the other hand, are billed with separate charges for their energy and peak requirements. As a class, they have a coincident load factor of approximately 82 percent. [68] Table 5 indicates that they should face a marginal energy charge

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[65] As mentioned in Chapter 2, B.C. Hydro accounts suggest that each customer class is now generating revenue which approximately meets the accounting costs attributed to it. In this paper, we will accept the present allocation of costs between customer classes. A strong argument can be made, however, that the cost allocation methodology, with its heavy emphasis on the capacity component, undercharges customers with high load factors.

[66] This load factor appears to be relatively constant across all levels of consumption within the class.

[67] Unlike the present situation, this customer charge could reflect cost differences in serving various customer types and densities.

[68] This is also relatively independent of the quantity consumed.

of 19 mills and an adjusted marginal capacity charge of 3 mills per KWH ($18.00 per KW) . At present, they are charged 4 and 6 mills respectively for an average price of approximately 10 mills per KWH.[69]

Our results indicate a substantial restructuring of the rate schedule for this customer class is in order. In addition to a dramatic reversal of the demand-energy split,[70] the combined recommended marginal energy and capacity rate is more than double that required to meet revenue requirements for the class. This gives rise to the traditional dilemma on the reconciliation of the two considerations.

One way to deal with this would be to charge the two marginal rates as flat rates for all levels of consumption and then provide an annual credit on the basis of the consumption level at an initial reference point.[71] In this way, the historical benefits would be returned to customers while at the same time they would face the appropriate marginal prices for any changes in their level of consumption.

In the case of general customers, the combined energy and capacity charges should approximate 24 mills per KWH. This is equivalent to the present average price for the class, so that a

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[69] The peak charge now in effect and that recommended are not directly comparable. It is currently based on the customer's non-coincident peak, while we suggest that it should be determined largely on the basis of the degree of coincidence with the system's peak.

[70] This is the term used in the electric utility industry to refer to the split between the peak and energy components of electrical demand.

[71] New large customers could also be given a right to the revenue surplus for their class by receiving a similar annual credit based on what a comparable firm consumed at the initial reference point. This consumption level establishes the size of each customer's claim on each year's surplus.

new flat rate at this level would require little adjustment to reconcile the economic and accounting criteria. However, within the class, it would involve a reduction in the bills for the large number of small customers at the expense of the small number of larger electricity users.[72]

There are a number of other considerations which could enter into the design of an appropriate rate structure. Many jurisdictions are considering time of day rates. This factor is not as relevant in the energy-critical B.C. Hydro system where a kilowatt-hour consumed at 5 a.m. reduces the annual energy capability by the same amount as one used at 5 p.m. Nevertheless, to the extent that petroleum-fired plants are needed to meet peak demand and that downstream facilities are capacity-related, some diurnal rate variations may yield a net economic benefit.[73] A worthwhile initial step would be to make the peak charge for large customers greatest when it coincided with the system's peak, rather than having its determination independent of this peak.

A more important time-varying rate, and one which could be introduced relatively easily, is the seasonal tariff. B.C. Hydro's annual peak is in the winter, a time when stream flow is at a minimum. Hence reservoirs must be designed so that they will not empty, once filled in the summer, during the winter period. At the same time, downstream facilities must be built to

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[72] A fuller discussion of possible rate structure designs, including some quantification of the impact of these changes, is contained in Appendix C.

[73] Naturally, any move entailing installation of new equipment to make this feasible should only be undertaken if the resulting marginal economic benefit exceeds the marginal cost involved.

meet the system's winter peak, and the petroleum-fired Units are most likely to be required in this season, both to meet peak requirements and to fulfil forecast annual energy deficiencies. Rates which reflected the higher planning and operating costs associated with the winter peak would enable some customers to alter their seasonal consumption patterns or switch to an energy source which was less seasonally sensitive.

A related approach with applicability to B.C. Hydro is a tariff which varied according to water conditions. As we have seen, the drier the year, the greater B.C. Hydro's reliance upon expensive thermal sources. Higher rates during dry years would encourage some customers to build and utilize alternative energy sources with long term storage capability when this proved to be to their economic advantage. Conversely, during wet years, water that would have spilled over the dams could be utilized by customers taking advantage of low rates that year. The introduction of interruptible rate classes with varying expected frequency and duration of interruption might be a useful way to indicate these seasonal and annual cost variations to the large customers.

Another consideration which could be incorporated in the design of a rate structure is the cost asymmetry between demand increases and decreases. A large aggregate reduction in demand would initially eliminate the cost of fuel at Burrard but would then effect few cost savings due to the large fixed costs associated with the system. If an aggregate decrease in demand was anticipated from the initial design of a rate structure, modifications could be introduced which reduced the marginal rate once a customer had cut back his demand by a certain amount. If, however, a reduction in the total demand level was not expected, then the higher rate could be maintained to provide those with the flexibility the chance to adjust their consumption and thus slow the rate of growth in system demand.

A related consideration is the appropriate timing of rate structure reform. Given that new hydro projects are currently under construction and will be coming on stream, the sudden introduction of an economically efficient rate structure could cut demand below what would be saved at Burrard in fuel costs, and provide a smaller base from which to cover the large fixed costs. A better approach would be to give five or six years notice of a change in rate structure (or move there gradually), so that projects not yet approved could be deferred while those underway would find a market for their output once completed. The timing of the introduction of a reformed rate structure and the approval of new generation projects are inevitably intertwined and must be carefully orchestrated.

6.2 Demand And System Response

6.2.1 Theory

Rate structure reform consistent with principles of economic efficiency will affect the demand for electricity and thus alter system planning, operation and ultimately, costs. The present B.C. Hydro load forecasts implicitly assume no change in the existing rate structure. Thus, we are interested in the impact on demand and costs of introducing the marginal prices discussed in the last section.[74]

The demand for electricity depends upon a number of factors including population and income levels, weather, its own marginal price and the price and availability of substitute energy forms. In the case of an industrial user, electricity represents one of many inputs required to produce its output. A profit maximizing firm is assumed to seek to combine these inputs in a manner which will minimize costs for a given level of output, subject to the production function defining the most efficient technical possibilities facing it. A consumer, on the other hand, is assumed to derive satisfaction from consumption, including the use of facilities requiring electricity, and to seek to maximize this satisfaction subject to a budget constraint limiting the combination and quantity of items available to him.

When the marginal price of electricity initially rises, only a limited number of possibilities to reduce its consumption are available. In the medium term, however, capital stock can be altered and the factor mix adjusted. In the long term, new, more electricity-conserving technology can be developed and lifestyles can be changed. We seek a means to quantify the effect over time of this change in marginal price, due solely to rate structure reform, when all other input prices and output

[74] It should be reiterated that we are concerned here with a change in rate structure, not level. We assume that B.C. Hydro's forecasts have taken into account anticipated changes in rate levels, and we seek now to examine the impact of altering rate structure given a rate level. In the longer term, rate structure reform will also affect rate levels.

levels remain unchanged.

The long run arc own price elasticity of the demand for electricity enables us to do just that. It measures the average change in electricity consumed relative to the average change in price, all other factors remaining constant. Algebraically,

$$e = ((Q2 - Q1)/(Q1 + Q2)) \;/\; ((P2 - P1)/(P1 + P2)) \quad \ldots\ldots(12)$$

where

e is the long run arc own price elasticity and is less than or equal to 0;

Q1 is the original consumption level;

Q2 is the new consumption level after the price change;

P1 is the original real marginal price; and

P2 is the new real marginal price.

Rearranging and using the absolute value of e,

$$Q2 = Q1 * (P1 + P2 - e * (P2 - P1)) \;/\; (P1 + P2 + e * (P2 - P1)) \quad \ldots\ldots(13)$$

Hence the long term adjustment to Q2 from Q1 as a result of a real marginal price increase from P1 to P2 can be determined given an appropriate value for e and some assumption about the adjustment process.

For an individual consumer, it is conventional to consider both income and substitution effects of a price change. In the present case, however, since we have altered only the marginal price and have left the average price unchanged, the income effect is likely to be negligible. Therefore it is ignored. Similarly, for an industrial consumer, the price effect is assumed to take place along a given isoquant, and thus output effects are not considered. The arc, rather than point, elasticity is used because it enables us to more accurately estimate the quantity adjustment from a relatively large marginal price change. Nevertheless, care must be exercised in the use of the elasticity estimates for very large price changes because of the inevitable non-linearity of the demand curve.

6.2.2 Modelling

In order to examine the implications of rate structure reform, several new features must be introduced to the model described in Chapter 4. Coefficients are used to read in the old marginal rates of 17, 15 and 10 mills per KWH and the new marginal rates of 26, 24, and 22 mills for residential, general and bulk customers respectively. Each class is also assigned a long run own price elasticity. Equation (13) is then used, given P1, P2, Q1, and e, to determine the revised Q2 for the current year and that six years hence for each customer class. The new rate structure is assumed to be fully implemented in 1981, and each year between 1977 and 1981 sees one-fifth of the ultimate consumption adjustment take place.

The choice of appropriate elasticity coefficients is as difficult as it is important. An outside study commissioned by B.C. Hydro estimated long run own price elasticities of -0.35 for residential customers and from -1.0 to -2.3 for non-residential customers, using monthly data for 5 regions during the 1964-1972 period (Wilson, 1974). Other studies tend to suggest somewhat higher residential elasticities and somewhat lower non-residential figures. Table 6 presents the results of various estimates of long run own price elasticities by customer

TABLE 6

A SURVEY OF ESTIMATED LONG RUN OWN PRICE ELASTICITIES OF ELECTRICITY DEMAND

Residential	
Anderson (1973)	-1.12
Federal Energy Administration (1976)	-1.46
Fisher and Kaysen (1962)	0.0
Griffin (1974)	-0.52
Halvorsen (1973)	-0.97
Houthakker and Taylor (1970)	-1.89
Houthakker, Verleger and Sheehan (1973)	-1.02
Mount, Chapman and Tyrrell (1973)	-1.20
Taylor, Blattenberger and Verleger (1976)	-0.78
Uri (1975)	-1.66
Wilson (1971)	-2.00
Wilson (1974)	-0.18 -0.35
Wilson (1974a)	-0.406
Commercial	
Federal Energy Administration (1976)	-0.38
Griffin (1974)	-0.51
Halvorsen (1973)	-0.91
Mount, Chapman and Tyrrell (1973)	-1.36
Uri (1975)	-0.85
Wilson (1974)	-1.0 -2.3
Industrial	
Anderson (1973)	-1.94
Baxter and Rees (1968)	-1.50
Federal Energy Administration (1976)	-0.15
Fisher and Kaysen (1962)	-1.25
Griffin (1974)	-0.51
Halvorsen (1973)	-1.24
Mount, Chapman and Tyrrell (1973)	-1.82
Uri (1975)	-0.35
Wilson (1971)	-1.33
Wilson (1974)	-1.2 -2.3

class.[75] As a base case, we shall use absolute value estimates of .4, .6 and .8 for residential, general and industrial classes respectively.[76] Sensitivity analysis using .2, .4, and .6 at the low end and .7, .8 and 1.2 at the high end will also be run.

The increase in the real marginal price for both residential and general customers is in the order of 50 percent, whereas it exceeds 100 percent for the bulk customers. The magnitude of this latter increase suggests that a reduced coefficient be used to reflect the non-linearity in the demand curve which may become important for this large an increase. However, in going from 10 to 22 mills, we disguise the fact that the energy rate is recommended to increase from 3 to 19 mills. Given that the stock of electricity consuming equipment is likely to be primarily affected by the energy charge, the use of the initial combined rate of 10 mills will tend to underestimate the impact of the increase. We therefore use the full elasticity

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[75] These results are presented to give an indication of the range of elasticity estimates that have been observed. Considerable variation in the methodology of the underlying statistical analysis, particularly as regards the price of electricity, makes some of these studies more relevant than others for the purposes of this paper.

[76] The estimates for bulk customers may in fact be too low given their tendency to ignore the large potential for electrical self-generation by some industrial users in B.C. Were the economic incentives present, greater use of the current and anticipated surplus of wood waste would be made. Such self-generation, with its large energy component (relative to capacity) and its tendency to peak in the winter months, would complement B.C. Hydro's system. The current low marginal rate for bulk customers, with a relatively large and ratchetted peak component, provides little encouragement for the displacement of Hydro's power by that which is self-generated. Moreover, the price which B.C. Hydro is offering for surplus energy, raised recently to between 5 and 6 mills, is far below the Authority's marginal energy costs and further discourages the installation of the economically appropriate quantity of self-generating capability.

estimate on the modified price change (10 to 22 mills) in an effort to offset the two conflicting biases.

A related consideration is the assumption we make about the impact on the system load factor of the reformed rate structure. On the one hand, the reduced peak charge for the bulk customers will tend to reduce the customer's load factor. However, a customer peak charge that was related to the degree of coincidence with the system's peak would tend to improve the system's load factor. In this analysis we assume the cancelling out of these two opposing forces and maintain the system load factor assumption of 63.5 percent.[77]

The new operating and expansion plan also provides a different base case from which marginal costs can be determined. By calculating the impact of the same variety of demand shocks on this base case as was undertaken in the last chapter, new estimates of marginal costs can be obtained. These revised figures will provide us with a better understanding of the degree of sensitivity of the estimates to the base case that is being examined.

6.2.3 Results

Table 7 highlights the implications of rate structure reform under the assumptions outlined in the last section. The results in the first column assume no change in the rate structure and are therefore identical to those presented in the last chapter. The next three show the effects of reformed rate

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[77] The extent to which altering the relative and absolute energy and peak prices affects the individual's and the system's load factor is an important,yet relatively unstudied, area.

TABLE 7

IMPLICATIONS OF RATE STRUCTURE REFORM

	NO RATE STRUCTURE REFORM	RATE STRUCTURE REFORM WITH DIFFERENT PRICE ELASTICITY ASSUMPTIONS		
		Low	Base Case	High
Growth Rate In Demand (%) (1976 - 1990)	9.0	7.8	7.0	5.7
Average Accounting Cost (1976 Mills per KWH) (1976 - 1990)	18.1	17.1	16.5	16.1
Gross Debt Outstanding In 1990 (Billions of Historic $)	17.1	13.4	11.2	10.2

structures under increasingly large own price elasticity assumptions. As would be expected, the greater these elasticities, the lower the growth rate in demand in the 1976-1990 period. In fact, the major readjustment in demand occurs between 1977 and 1981, with slight declines occurring in two years under the high elasticities case. Once the new rate structure has been fully implemented, demand is assumed to respond primarily to the various factors implicit in the Task Force projections and averages 8.5 percent in all cases in the 1982-1990 period.

The reduced growth rates defer the need to develop more expensive new generation sources,[78] thereby reducing both average accounting costs and investment. Row two of Table 6 is derived by taking all accounting costs in each year between 1976 and 1990, adding any net income, subtracting any export revenue, converting the total into 1976 dollars, dividing by the quantity of energy generated by B.C. Hydro and averaging the results over this period. The reduction in real average unit net accounting costs ranges from 5.4 (low elasticities) to 11.0 percent (high elasticities) with a value of 8.8 percent under the base case elasticities assumption.

The last row of the table indicates the anticipated gross debt outstanding (attributable to the electric service) of B.C. Hydro in 1990 in billions of historic dollars. This serves as a good proxy for total investment during this period since most of

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[78] These new sources are more expensive than the old ones both in real terms and because of the distortions of the accounting system (particularly during periods of inflation) discussed in the last chapter.

the Authority's capital requirements will continue to be met by debt financing. The reduction in the 1990 debt level is 33.1 percent using the base case elasticities, with extremes of 20.4 and 38.1 percent under the alternative elasticity assumptions.

The table also reveals the existence of decreasing returns from growth rate reductions over the 1976-1990 period. The first one percent reduction in the growth rate has a larger impact on average costs than does the next one percent. This results from the high proportion of fixed costs associated with the B.C. Hydro system which reduces the attractiveness of demand growth reductions in the first half of this period. Indeed, it is only after 1982 that the opportunities for cost savings resulting from the different growth rates become particularly apparent.[79]

An analysis of marginal economic costs similar to that performed in the last chapter was also undertaken in which demand shocks of from 10 to 500 million KWH in both directions and with different load factors were imposed on the forecast using the base case demand elasticities of .4, .6 and .8. The results were compiled in the same manner as those presented in Table 5. The average combined marginal energy and capacity cost for large customers was found to be 22.1 mills per KWH using the 7.0 percent growth rate compared with the earlier result of 22.6 mills with the 9.0 percent rate of growth over the 1976-1990 period. The energy component rose slightly while the peak component fell from 3.2 to 2.4 mills per KWH at the system load

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[79] A system with a greater thermal component would derive more immediate benefits from demand growth reductions. The diminished flexibility in the B.C. Hydro case re-emphasizes the importance of co-ordinating the introduction of rate structure reform with the approval of major new projects.

factor. In light of the apparent stability in the marginal cost estimates, no redesign of rate structures and re-estimation of demand was deemed necessary to reflect the new, slightly lower, marginal economic costs.

7. SUMMARY AND CONCLUSIONS

The primary purpose of this paper has been to develop and apply a marginal economic costing methodology appropriate for the predominantly hydro-electric system of B.C. Hydro. The basic approach adopted is one whereby each component of the demand for electricity is allocated those incremental economic costs (savings) which a change in its demand will cause. This differs fundamentally from the technique now employed under which the accounting costs associated with in-service plant are split between the components of demand according to somewhat arbitrary accounting criteria.

The two approaches are reconciled by adopting a rate structure which equates marginal price with marginal economic cost while keeping average price equal to average accounting costs for each customer class. For the larger users (both within each class and within the system), this leads to substantially higher marginal rates from those now in effect. In particular, the economic analysis attaches far greater weight to the energy component of demand in the energy-critical B.C. Hydro system than does the accounting approach. The results of this analysis are summarized in Table 8.

The reduction in the growth rate in the demand for electricity induced by the new marginal prices is quantified using assumptions about each customer class's own price elasticity of demand. The ensuing decline in costs as new, more expensive projects are deferred is also calculated. These results were presented in Table 7 and indicated a reduction of over 9 percent in the real average unit annual accounting costs and over 40 percent in the gross debt outstanding in 1990 using the median elasticity estimates over the case with no rate structure reform.

The purpose of moving towards marginal cost pricing is to enable each individual consumer and firm to achieve its objectives in a manner which is least costly to society. The setting of the marginal price below its real economic value and that required to make an electricity-conserving technology attractive will lead to economic inefficiencies. Such subsidization of the marginal price of electricity cannot be in society's long term best interests.

The relevance of these concerns is now being recognized by many electric utilities. Some are moving to reform their rate structures accordingly. The situation can be particularly acute with predominatly hydro-electric utilities where recovery of the large fixed costs is often sought through high charges on initial consumption blocks. This leads to the latter blocks being priced well below current marginal economic costs.

There is some evidence of a recognition of these concerns within B.C. Hydro. The moves towards flatter rate structures and increased energy charges are clearly in the right direction. Yet a recent statement by the Chairman of the Authority (Bonner, 1977), indicating that the "ideal" rate structure would have a very large front end charge with the balance being collected by a flat energy charge, is at odds with the economic principles outlined in this paper. Indeed, there does not now appear to be any strong political or senior management committment to reform rate strucutes in accordance with the objective of economic

TABLE 8

MARGINAL AND AVERAGE PRICES OF ELECTRICITY (1977¢/KWH)

<table>
<tr><th rowspan="3">CUSTOMER CLASS</th><th colspan="4">MARGINAL</th><th>AVERAGE</th></tr>
<tr><th colspan="2">EXISTING
(as of May, 1977)</th><th colspan="2">PROPOSED</th><th>EXISTING/PROPOSED</th></tr>
<tr><th>Peak</th><th>Energy</th><th>Peak</th><th>Energy</th><th>Peak and Energy</th></tr>
<tr><td rowspan="2">Residential</td><td colspan="2" rowspan="2">2.0</td><td>.8</td><td>2.0</td><td rowspan="2">3.1</td></tr>
<tr><td colspan="2">2.8</td></tr>
<tr><td rowspan="2">General</td><td colspan="2" rowspan="2">Varies Widely</td><td>.6</td><td>2.0</td><td rowspan="2">2.9</td></tr>
<tr><td colspan="2">2.6</td></tr>
<tr><td>Bulk</td><td>.6
(approx.)</td><td>.4</td><td>.3</td><td>2.0</td><td>1.1</td></tr>
</table>

efficiency.

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APPENDIX A

B.C. HYDRO AND POWER AUTHORITY

STATEMENT OF INCOME

FOR THE YEAR ENDED 31 MARCH 1976

Gross revenues, excluding Provincial Government special subsidy		$ 492,163,490
Expenses:		
Salaries, wages and employee benefits		157,000,822
Materials and services		102,342,574
Grants, school taxes and water rentals		39,531,674
Depreciation		72,779,127
Interest on debt	213,390,701	
Less -		
Interest charged to construction	61,578,833	151,811,868
		523,466,065
Income (loss) before Provincial Government special subsidy		(31,302,575)
Provincial Government special subsidy		32,600,000
Net Income		$ 1,297,425

British Columbia Hydro and Power Authority
Electric Transmission System at 31 March 1977 with planned additions
LEGEND
Hydroelectric Generating Stations
Diesel-Electric Generating Stations
Gas-Turbine-Electric Generating Stations
Substations
Transmission Lines 60 kV-360 kV (existing and under construction)
Transmission Lines 500 kV (existing and under construction)
Transmission Lines 60 kV-360 kV (planned)
Transmission Lines 500 kV (planned)
Vancouver Area
MAJOR GENERATING PLANTS
Alouette: Hydroelectric
Burrard: Steam-Turbine
Lake Buntzen: Hydroelectric
Port Mann: Gas-Turbine
Ruskin: Hydroelectric
Stave Falls: Hydroelectric
MAJOR SUBSTATIONS
Arnott
Atchelitz
Barnard
Camosun
Cypress
Dal Grauer
Horne-Payne
Ingledow
Kidd, Nos. 1 and 2
Mainwaring
Meridian
Murrin
Newell
Walters
Victoria Area
MAJOR SUBSTATIONS
Colwood
Esquimalt
George Tripp
Goward
Horsey
Prince George Area
MAJOR SUBSTATIONS
Canreed
Northwood
Patricia
Pineview
Prince George
Williston
ALASKA (U.S.A.)
BRITISH COLUMBIA
ALBERTA
UNITED STATES OF AMERICA
CANADA
QUEEN CHARLOTTE ISLANDS
VANCOUVER ISLAND
PRINCE GEORGE (See Legend)
VANCOUVER (See Legend)
VICTORIA (See Legend)
TELEGRAPH CREEK
DEASE LAKE
EDDONTENAJON
ATLIN
FORT NELSON
STEWART
KITSAULT
W.A.C. BENNETT DAM
GORDON M. SHRUM
FORT ST. JOHN
BOUNDARY LAKE
PORTAGE PASS
PEACE RIVER
CHETWYND
DAWSON CREEK
WILLISTON LAKE
HAZELTON
AIYANSH
MORFEE LAKE
SMITHERS
PRINCE RUPERT
OLDFIELD
RUPERT
TERRACE
TELKWA
BABINE
KENNEDY
MASSET
SKEENA
HOUSTON
PORT CLEMENTS
FALLS RIVER
KITIMAT
BURNS LAKE
FORT ST. JAMES
McEWAN
SALMON VALLEY
GLENANNAN
VANDERHOOF
SANDSPIT
UPPER FRASER
COLEBANK
BARLOW
McBRIDE
QUESNEL
MARGUERITE
GIBRALTAR
BELLA COOLA
BELLA BELLA
ANAHIM LAKE
VALEMOUNT
SODA CREEK
TATLA LAKE
WILLIAMS LAKE
BOSS MOUNTAIN
BLUE RIVER
MICA
MICA DAM
AVOLA
VAVENBY
100 MILE HOUSE
PORT HARDY
KEOGH
KELLY LAKE
BARRIERE
GOLDEN
JEUNE LANDING
LA JOIE
HEFFLEY CREEK
REVELSTOKE
COLUMBIA RIVER
BRIDGE RIVER
SETON
SAVONA
KAMLOOPS
SPILLIMACHEEN
DUNCAN BAY
ZEBALLOS
CAMPBELL RIVER
ASHCROFT
WALTER HARDMAN
TAHSIS VILLAGE
HIGHLAND
ASHTON CREEK
ATHALMER
LYTTON
NICOLA
SHUSWAP
GOLD RIVER
POWELL RIVER
FOREST VIEW
CHEAKAMUS
SPENCES BRIDGE
VERNON
NAKUSP
CHEEKYE
MERRITT
DUNCAN DAM
PUNTLEDGE
CLOWHOM
BOSTON BAR
CANAL FLATS
ASH RIVER
WESTBANK
MONASHEE
WHATSHAN
NEW DENVER
DUNSMUIR
SECHELT
GREATA
AHOUSAT
PRINCETON
KIMBERLEY
ELKFORD
ALBERNI
KOOTENAY CANAL
TOFINO
NANAIMO
GEORGIA
HOPE
CRANBROOK
NATAL
FERNIE
ABERFELDIE
WAHLEACH
HUGH KEENLEYSIDE DAM
ELKO
BAMFIELD
DOUGLAS
ROSEDALE
VANCOUVER ISLAND TERMINAL
TRAIL
7 MILE
SELWAY
SELKIRK
KINGSGATE - YAHK
JORDAN RIVER
N
40 30 20 10 0 40 80 120 160 MILES

C. APPENDIX C

This appendix seeks to serve two purposes. The first is to update the basic results from the text using a more recent electrical demand forecast by B.C. Hydro. The second is to discuss alternative ways of reforming the rate structure and to analyse some of the implications associated with each of them.

The main text of this paper presented results based upon the electrical demand forecast given in the May 1975 Task Force Report. The forecasted average annual compound growth rate was 9.3 percent over the 1975-1990 period, or 9.0 percent during the 1976-1990 period (see Table 7). In September 1976, B.C. Hydro produced a new forecast which, using the same 1976 base, yielded a 1976-1990 average annual growth rate of 8.1 percent.[80] This new forecast continued to assume no rate structure reform, but did reflect reduced expectations about economic activity in the province during these years. The implications for average real unit accounting costs and gross outstanding debt in 1990 are indicated in Table C-1. As would be expected, they are lower than the equivalent results in Table 7 which uses the original demand forecast.

The basic economic principle of rate structure design is that marginal price should equal marginal economic cost for each

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[80] B.C. Hydro's management has been reluctant to release the specifics of this new demand forecast. I have had to assume that each customer class maintains the same share of total demand as under the Task Force projection and that the system load factor assumption of 63.5 percent continues to be appropriate.

TABLE C-1

IMPACT ON B.C. HYDRO OF ALTERNATIVE RATE STRUCTURES

	NO RATE STRUCTURE CHANGE	RATE STRUCTURE CHANGE	
		BASE CASE (MP=MC with AP=AC)	FULL M.C.P. (MP=MC for all Units)
Growth Rate In Demand (%) (1976 - 1990)	8.1	5.4	5.4
Average Accounting Cost (1976 Mills per KWH) (1976 - 1990)	17.5	16.0	13.7
Gross Debt Outstanding In 1990 (Billions of Historic $)	12.3	8.6	1.1

customer class. This gives rise to the question of the appropriate intra-marginal price. In the text of this paper, intra-marginal prices were assumed to be adjusted so that average prices were equal to average accounting costs for each class. Because of the proximity of the proposed marginal economic costs and the existing average accounting costs for the residential and general classes, a reconciliation of the economic and accounting criteria was not anticipated to be difficult. A flat rate at the new marginal economic cost, supplemented by a small service charge, would satisfy both criteria for the classes as a whole. There would, of course, be a general shift in costs from smaller electricity consumers to the larger ones within each of these classes.

The difficulties in implementing a new rate structure would likely arise with the fifty bulk customers. For this class, the proposed marginal economic costs were more than double the present accounting costs. In the text, a "valuation day" approach was suggested in which the surpluses for the class from full marginal cost pricing would be returned to each customer on the basis of his consumption on an initial reference date. This is perhaps the most economically "pure" way to deal with the issue, although it may give rise to claims of inequity. It is, however, an approach used frequently in other matters, from income tax on capital gains to compliance with anti-pollution standards. The Ontario Hydro study (1976c) has suggested that the surpluses from large users be returned on the basis of the customer's consumption three years earlier. Regardless of the method chosen to reconcile the two criteria, however, the class as a whole will be better off since the higher marginal prices will induce some to reduce their consumption, thereby slowing the utility's growth and keeping average costs below what they otherwise would have been.[81]

An alternative approach would be to ignore the accounting and revenue constraints and apply the appropriate marginal economic costs for all units of consumption within each class. This would avoid some of the administrative and implementation problems of the previous method, but could cause a larger impact on customers' bills, particularly in the bulk class. Because marginal economic costs exceed accounting costs, the question of the surplus revenue that would result must be addressed.

At one extreme, the surplus profits could be transferred to the provincial government each year and put to a variety of uses. For example, a fund could be established to facilitate conversion by customers to electricity-conserving technologies, to attract new industry or to provide reductions in income taxes. Any of these uses would be more economically efficient than the continued subsidization of the marginal price of electricity. Over 4 billion historic dollars of additional profits would be generated between 1981 and 1990 with a full marginal cost pricing scheme (assuming median elasticities) as compared with the case of no rate structure reform.

At the other extreme, the new profits could be retained by B.C. Hydro and used to finance expansion and/or retire

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[81] This is analagous to the common property problem where the economic rent is dissipated from rising average costs because each individual does not face the full marginal costs associated with his actions.

outstanding debt, thereby reducing the average cost of power to B.C. Hydro yet further. The results of this full marginal cost pricing are also shown in Table C-1, and are contrasted with those from the rate structure suggested in the text of this paper. In both cases, the full effect of the reform is assumed to be felt by 1981 and the median elasticity estimates are used.

Having examined the impact on B.C. Hydro of these various rate reform possibilities, we turn now to review the effects of these various proposals on the total revenues yielded by each of the customer classes. These results are contained in Table C-2. The first column indicates the total revenue (in historic dollars) to be derived from each class between 1981 and 1990 with no rate structure reform. The average price in each class is assumed to be adjusted annually by a common percentage in order that B.C. Hydro's revenues equal its costs (which include a desired profit margin).

The next column shows the cumulative revenue (with the percentage change from column (1)) under the rate setting procedures used in the text of this paper. Marginal prices are set equal to marginal economic costs while average prices are equated with average accounting costs. Revenues fall both because of lower volumes and because of a reduction in average unit accounting costs.

The third column shows the revenue effect if the marginal economic costs derived in the paper are applied to all units of consumption in each customer class, assuming the demand adjustment inherent in the median elasticity estimate. This is in contrast to the final column's results which depict the

TABLE C-2

IMPACT ON CUSTOMERS OF ALTERNATIVE RATE STRUCTURES

CUMULATIVE REVENUE (Millions of Historic $)

(1981 - 1990)

CUSTOMER CLASS	NO RATE STRUCTURE REFORM	RATE STRUCTURE REFORM: BASE CASE (MP=MC with AP=AC, Median Elasticities)	RATE STRUCTURE REFORM: FULL M.C.P. (MP=MC for all Units, Median Elasticities)	RATE STRUCTURE REFORM: FULL M.C.P. (MP=MC for all Units, Zero Elasticities)
Residential	6456	4763 (-26.2%)	5687 (-11.9%)	6725 (+4.2%)
General	7499	4923 (-34.4%)	5856 (-21.9%)	7734 (+3.1%)
Bulk	4145	1941 (-53.2%)	4430 (+6.9%)	8224 (+98.4%)

effect when there is no demand adjustment to the full marginal cost pricing. These figures would represent the impact if no substitution possibilities became attractive for any customer under the reformed rate structure.

The total cost impact on each customer class would depend on the cost of the alternatives available to its members. The fourth column represents the most extreme cost impact, since it assumes full marginal cost pricing, no demand response, and no benefits from the surplus revenues to be generated by B.C. Hydro. The very slight rise in electricity bills for the residential and general classes under this extreme condition indicates that they would almost certainly benefit as a class under more realistic assumptions. And by assisting bulk users with conversions to electricity-conserving equipment and/or with reductions in their costs through grants or tax reductions, they too could be made better off under marginal cost pricing.

This appendix has presented some rather extreme positions on how rate structure reform could be accomplished. A realistic approach might combine these different methods. Average prices for each class could be set somewhere between the marginal economic and average accounting costs. Some of the resulting surplus could be used to reduce B.C. Hydro's debt while the rest could be applied to reduce costs for those classes adversely affected by the rate reform. Other ways could also be devised which turn into reality the theoretical improvement in social welfare possible from rate structures consistent with economic principles.

D. APPENDIX D

D.1 List Of Variables, Coefficients, And Definitions

D.1.1 Endogenous Variables

All Variable Names Ending With $76 Are Measured In Millions Of 1976 $
All Variable Names Ending With $H Are Measured In Millions Of Historic $
All Variable Names Ending With $ Are Measured In Millions Of Current $
All Electricity Units Are Millions Of KWH Per Year Unless Otherwise Stated

name	description
C1KWH$76	Net Cost Per KWH Generated
C2KWH$76	Cost Per KWH Generated
COPFIX$	Fixed Operating Costs For Complete System
COPFIX1$	Fixed Operating Costs To 230 KV Level
COPVAR$	Variable Operating Costs
COP$76	Annual Operating Costs Of Projects
COSTS$	Total Operating And Capital Costs
DBULK	Demand By Bulk Class
DEPACC$H	Accumulated Depreciation On New Facilities For School Tax Purposes
DEPREC$	Depreciation Charges
DEXPORT	Satisfied Export Demand
DGEN	Demand By General Class
DGROSS	Total Demand Including Losses
DGROSSF	Future Total Gross Demand
DIND	Commercial And Industrial Demand
DLOSS	Losses On Integrated System
DPEAK	Maximum Annual One-hour Demand (MW)
DPEAKF	Future Peak Demand
DRES	Residential Demand
DTOT	Total Demand Net Of Losses
DTOTF	Future Total Net Demand
DWKPL	West Kootenay Power And Light's Incremental Demand
FINREQ	Financial Requirements Not Internally Generated($)
FINREQB	Financial Requirements To Be Met By Debt Financing($)
I$	Investment
IDIST$76	Investment In Distribution Facilities
IGEN$76	Investment In Generation Projects
ITRF$76	Investment In Transformation
ITRS$76	Investment In Major Transmission And Sub-transmission Projects
ITRS1$76	Investment In Major Associated Transmission Projects
INT$	Total Interest Charges
INTOLDB$	Annual Interest Payments Remaining On Bonds Issued Prior To 1976
KELEC	Complete Stock Of Electricity Supply Capital Approved After 1974
KELEC3	Stock Of Electricity Supply Capital ($76) To Serve Largest Customers

KELEC4	Stock Of Electricity Supply Capital ($76) To Serve Smallest Customers
KPISC$H	New Coal Generation Plant In Service
KPISD$H	New Distribution Plant In Service
KPISG$H	New Gas Turbines In Service
KPISH$H	New Hydro Plant In Service
KPIST$H	Transmission And Transformation Plant In Service
KPISTF$H	New Transformation Plant In Service
KPISTS$H	Major Transmission And Sub-transmission Plant In Service
KPIS$76	Total New Plant In Service
KPISC$76	Stock Of Post-74 Coal-fired Plant In Service
KPISD$76	Stock Of Post-74 Distribution Plant In Service
KPISG$76	Stock Of Post-74 Gas Turbine Plant In Service
KPISH$76	Stock Of Post-74 Hydro-electric Plant In Service
KPISM$76	New Miscellaneous Plant In Service For 230 KV Level Customers
KPIST$76	All New Transmission And Transformation Plant
KPST1$76	Stock Of New Major Associated Transmission Projects In Service
KPST3$76	All New Transmission And Transformation Plant In Service To Serve Customers At The 230 KV Level
KPVC1$76	Complete Discounted Cost For Electricity Supplied From Projects Approved After 1974
KPVC3$76	Present Value Of Costs Associated With Supplying Largest Customers
KPVC4$76	Present Value Of Costs Associated With Supplying Smallest Customers
KPVELEC1	Present Value Of Actual Energy Supplied (KWH) For Projects Approved After 1974
KPVELEC2	Present Value Of Actual Peak Power Supplied(MW) For Projects Approved After 1974
KPVELEC3	Present Value Of Actual Energy Produced (KWH)
KPVELEC4	Present Value Of Actual Capacity Produced (MW)
LNEW$H	Stock Of Post-75 New Bonds Outstanding
LOLD$H	Stock Of Debt Issued Prior To 1976 Still Outstanding At End Of Each Period
MISS	Fraction Of Revenue Surplus/deficit
NOCUST	Number Of Electricity Customers (M)
PBULK	Average Bulk Price($)
PBULK$76	Average Bulk Price
PEXPORT	Average Export Price($)
PEXP$76	Average Export Price
PGEN	Average General Price($)
PGEN$76	Average General Price
PIND	Average Commercial/industrial Price($)
PIND$76	Average Industrial And Commercial Price
PKWHCST1	Complete Discounted Cost ($76) Per KWH Actual Energy Supplied
PRES	Average Residential Price($)
PRES$76	Average Residential Price
PWCOST1	Complete Discounted Cost ($76) Per Watt Of Peak Power Supplied
PWKPL	Average West Kootenay Power And Light Price($)
PWKPL$76	Average Price To WKPL
RESMAR	Actual Reserve Capacity Margin

RESMARD	Desired Reserve Capacity Margin
SCAP	Actual Capacity Capability (MW)
SCAPD	Desired Capacity Capability (MW)
SCAPH	Hydro Generation Capacity Capability(MW)
SCAPSURP	Surplus (deficit) Of Actual Capacity Capability Over Desired Capacity Capability(MW)
SENER	Total Energy Generated
SENERB	Actual Energy Produced At Burrard
SENERBC	Burrard's Energy Capability
SENERC	Actual Energy Produced From Hat Creek Coal
SENERCAP	Total Energy Capability
SENERCC	Hat Creek Coal Capability
SENERG	Actual Energy Produced From Gas Turbines
SENERGC	Gas Turbines Energy Capability
SENERH	Actual Energy Produced From Hydro Sources
SENERHC	Hydro-generated Energy Capability
SENERK	Actual Energy Produced From East Kootenay Coal
SENERKC	East Kootenay Coal Energy Capability
SENERM	Actual Energy Imported From Other Utilities
SFPAYMT$	Annual Sinking Fund Payment And Additional Funds Required For Bonds Maturing Before 1982
TGRANTS	'Grants'($)
TLAND	Land Taxes($)
TLOCAL	All Local Taxes($)
TSCHOOL	School Taxes($)
TWATER	Water Licence Costs($)
YBULK	Revenue From Bulk Sales($)
YBULKMCP	Revenue From Bulk Sales Under Full M.C.P.($)
YEXPORT	Revenue From Export Sales($)
YGEN	Revenue From General Sales($)
YGENMCP	Revenue From General Sales Under Full M.C.P.($)
YIND	Revenue From Commercial And Industrial Sales($)
YRES	Revenue From Residential Sales($)
YRESMCP	Revenue From Residential Sales Under Full M.C.P.($)
YSURPMCP	Additional Net Income Under Full M.C.P.($)
YTOT	Total Revenues($)
YTOTMCP	Total Revenue From Sales Under Full M.C.P.($)
YTOTSURP	Total B.C. Hydro Net Income Under Full M.C.P.($)
YWKPL	Revenue From WKPL Sales($)

D.1.2 Exogenous Variables

All Variable Names Ending With $76 Are Measured In Millions Of 1976 $
All Variable Names Ending With $H Are Measured In Millions Of Historic $
All Variable Names Ending With $ Are Measured In Millions Of Current $
All Electricity Units Are Millions Of KWH Per Year Unless Otherwise Stated

name	description
BULKRED	Bulk Class Demand Change
COVERAGE	Interest Coverage Policy Coefficient
DBULK	Demand By Bulk Class
DBULKF	Future Demand By Bulk Class
DGEN	Demand By General Class
DGENF	Future Demand By General Class
DGROSSF	Future Total Gross Demand
DIND	Commercial And Industrial Demand
DLOSS	Losses On Integrated System
DPEAKF	Future Peak Demand (MW)
DRES	Residential Demand
DRESF	Future Demand By Residential Class
DTOTF	Future Total Net Demand
DWKPL	West Kootenay Power And Light's Incremental Demand
DWKPLF	Future Demand By WKPL.
GENRED	General Class Demand Change
IDC$	Interest During Construction
IDCG1$...IDCG50$	Annual Interest During Construction For Each Generation Project
IDCT1$...IDCT45$	Annual Interest During Construction For Each Associated Major Transmission Project
IDST1$76	Investment In Distribution Facilities For New Customers
IDST2$76	Investment In Distribution Facilities For Growth By Existing Customers
IG1$...IG50$	Investment On Each Generation Project
IGEN$	Investment In Generation Projects
IGEN$76	Investment In Generation Projects
IMISC$76	Investment In Other Electric Plant
INTRED$H	Reductions In Interest Charges Due To Maturing Of Bonds Issued Before 1976
IT1$...IT45$	Investment On Each Major Asssociated Transmission Project
ITRF1$76	Investment In Transmission Transformation
ITRF2$76	Investment In Sub-transmission Transformation
ITRS1$	Investment In Major Associated Transmission Projects
ITRS1$76	Investment In Major Associated Transmission Projects
ITRS2$76	Investment In Non-associated Major Transmission Projects
ITRS3$76	Investment In Sub-transmission Lines
KPISC$H	New Coal Generation Plant In Service
KPISC$76	Stock Of Post-74 Hat Creek Plant In Service
KPISG$H	New Gas Turbines In Service

KPISG$76	Stock Of Post-74 Gas Turbine Facilities In Service
KPISH$H	New Hydro Plant In Service
KPISH$76	Stock Of Post-74 Hydro-electric Plant In Service
KPISK$76	Stock Of Post-74 East Kootenay Coal-fired Plant In Service
KPIST$76	All New Transmission And Transformation Plant
KPIST1$H	New Major Transmission Plant In Service
KPIST2$H	New Non-associated Major Transmission And Subtrans-Mission Plant In Service
KPSTF$76	New Transformation Plant In Service
KPST1$76	New Major Transmission Plant In Service
KPST2$76	New Non-associated Transmission And Sub-transmission Plant In Service
KPST3$76	All New Transmission And Transformation Plant In Service To Serve Customers At The 230 KV Level
KPST4$76	Stock Of New Sub-transmission Transformation Plant In Service
LMWOSF$	Shortfall In Sinking Fund For Bonds Maturing After 1981
LOLDM$H	Stock Of Debt Issued Prior To 1976 That Matures Each Year
NOCUST	Number Of Electricity Customers (M)
PEXOG	Price Levels
QSTART	Switch Indicating Energy Production By Projects
RESMARDF	Future Desired Reserve Margin
RESRED	Residential Class Demand Change
SCAPB	Capacity Capability Of Burrard Plant (MW)
SCAPC	Capacity Capability Of Hat Creek Plants (MW)
SCAPDF	Desired Future Capacity Capability(MW)
SCAPF	Future Capacity Capability(MW)
SCAPG	Capacity Capability Of Gas Turbine Plants (MW)
SCAPH	Capacity Capability Of Hydro-electric Plants (MW)
SCAPK	Capacity Capability Of East Kootenay Plants (MW)
SECNEW	New Energy Capability
SENCAC1	Hat Creek's Capability At Year End
SENCAPF	Future Expected Energy Capability
SENERBAC	Burrard's Energy Capability
SENERCAC	Average Hat Creek Coal Capability Throughout Year
SENERGAC	Average Gas Turbines Energy Capability Throughout Year
SENERHAC	Average Energy Capacity Throughout Year From Hydro Sources During Average Rainfall Periods
SENERHCC	Average Energy Capacity Throughout Year From Hydro Sources During Critical Rainfall Periods
SENERKAC	Average East Kootenay Coal Energy Capacity Throughout Year
SENGAC1	Gas Turbines Energy Capability At Year End
SENHAC1	Energy Generation Capacity From Hydro-electric Sources During Average Rainfall Period At Year End
SENHCC1	Energy Generation Capacity From Hydro-electric Sources During Critical Rainfall Period At End Of Each Year
SENKAC1	Energy Generation Capacity From East Kootenay Coal At Year End
STARG1...STARG50	Approval Dates For Each Generation Project

START1...START45
Approval Dates For Each Associated Major Transmission Project
STPNOM Nominal Rate Of Social Time Preference
TOTRED Total Demand Change Due To Price Change

D.1.3 Coefficients

Values Shown Are Those In The Base Case

no.	value	description
1849	63.5	Annual Load Factor (converts MM KWH To MW)
1850	0.057	Switch - Indicates Depreciation Used For Economic Analysis
1851	1.2	Interest During Construction For Transmission Projects
1852	1.1	Interest During Construction For Transformation Projects
1853	.0049	Annual Fixed Operating Cost Coefficient For Hydro Facilities
1854	.024	Annual Fixed Operating Cost Coefficient For Coal Facilities
1855	.0108	Annual Fixed Operating Cost Coefficient For Gas Facilities
1856	.0095	Annual Fixed Operating Cost Coefficient For Transmission And Transformation Facilities
1857	.033	Annual Fixed Operating Cost Coefficient For Distribution Facilities
1858	.015	Average Mill Rate In 1976
1859	.01	Rate Used In Determining Annual 'grants'
1860	.0005	Water Licence Charge ($MM/MW)
1861	.00025	Water Licence Charge ($/KWH)
1862	.0055	Annual Variable Operating Cost Coefficient For Hat Creek Coal Generation
1863	.0059	Annual Variable Operating Cost Coefficient For East Kootenay Coal Generation
1864	.0187	Annual Variable Operating Cost Coefficient For Burrard Generation (gas-oil Price Parity)
1865	.03	Annual Variable Operating Cost Coefficient For Gas Turbines
1866	0.0	Demand Shock
1867	.88	Integrated Electric Plant In Service:total B.C. Hydro Plant In Service
1868	.94	Net Out Interest Earned From Sinking Fund Investments
1869	227.69	Gross Interest On Debt For B.C. Hydro In 1975
1870	.01	Percent Of Outstanding Pre-1976 Debt Contributed Annually To Sinking Fund
1871	.0175	Percent Of Outstanding Post-1975 Debt Contributed Annually To Sinking Fund
1872	.1	Annual Nominal Interest Rate For B.C. Hydro Post-1975 Debt
1873	.5	Proportion Of Electricity B.C. Hydro Seeks To Export Actually Purchased
1874	.0143	Inverse Of Expected Service Life Of Hydro Facilities
1875	.0286	Inverse Of Expected Service Life Of Coal And Gas Turbine Facilities
1876	.0222	Inverse Of Expected Service Life Of Transmission Facilities
1877	.0272	Inverse Of Expected Service Life Of Distribution Facilities
1878	.02	Average Import Price Of Electricity
1879	.0095	Export Price Of Electricity
1880	1.25	Real Capital Cost Adjustment For New Generation

		Facilities
1881	1.0225	Real Annual Wage Rate Adjustment
1882	1.02	Real Annual Coal Value Adjustment
1883	1.02	Real Annual Gas/oil Value Adjustment
1885	63.5	Annual Load Factor For Demand Shock
1886		Gross Demand Shock - Set In Model
1887	76.	Initial Year Of Demand Shock
1888	0.0	Demand Shock In 1976 Only
1889	0.0	Shock In Number Of Customers
1890	.075	Private After-tax Real Cost Of Funds
1891	0.0	Inverse Of Service Life Used - Set In Model
1894	.075	Real Rate Of Social Time Preference
1895	.03	Corporation Tax In Other Industry
1900	0.0	Set In Model - Supply Approval Date Shock
1901	1.39	Adjustment From $74 Estimate To $76 Including
1902	1.39	Corporate Overhead For Each Group Of Major Generation
1903	1.39	And Transmission Projects
1904	1.39	Continued
1905	1.39	
1906	1.39	
1907	1.39	
1908	1.39	
1909	1.53	
1910	1.53	
1911	1.53	
1912	1.47	
1913	1.39	
1914	1.47	
1915	1.47	
1916	1.39	
1917	1.39	
1918	1.53	
1919	1.53	
1920	1.47	
1921	1.47	
1922	1.47	
1923	1.47	
1931	1.39	
1932	1.39	
1933	1.39	
1934	1.39	
1935	1.39	
1936	1.47	
1937	1.47	
1938	1.47	
1939	1.47	
1940	1.47	
1941	1.47	
1942	1.47	
1943	1.47	
1944	1.47	
1945	1.47	
1951	1.39	
1952	1.39	
1953	1.39	
1954	1.39	

1956	1.39	
1958	1.39	
1959	1.39	
1960	1.39	
1971	1.39	
1972	0.0	Real Rate Of Inflation - Set In Model
1981	1.39	Continuation Of Capital Cost Adjustment Factors For Each
1986	1.39	Group Of Major Generation And Transmission Projects
1988	1.39	
1990	1.39	
1994	1.39	
1995	1.39	
2000	.062	Investment In Non-associated Major Transmission($MM/MW)
2001	.026	Investment In Sub-transmission Lines ($MM/MW)
2002	.012	Investment In Transmission Transformation ($MM/MW)
2003	.036	Investment In Sub-transmission Transformation ($MM/MW)
2004	1.25	Investment In Distribution Per New Customer($MM/M Cust)
2005	.019	Investment In Distribution Per Current Cust. ($MM/MW)
2006	.017	Investment In Other Electric Plant ($MM/MKWH)
2007	0.0	Switch-indicates Critical Rain Period If Not Zero
2010	0.0	Switch- Indicates Unit For Marginal Cost Analysis
2011	0.0	Switch-indicates Project For Marginal Cost Analysis
2012	0.0	Switch-indicates Use Of Demand Changes From Price Effects
2013	17.0	Old Marginal Price For Residential Class
2014	26.0	New Marginal Price For Residential Class
2015	15.0	Old Average Marginal Price For General Class
2016	24.0	New Marginal Price For General Class
2017	10.0	Old Combined Marginal Price For Bulk Class
2018	22.0	New Combined Marginal Price For Bulk Class
2019	0.4	Absolute Value-own Price Elasticity-residential Class
2020	0.6	Absolute Value-own Price Elasticity-general Class
2021	0.8	Absolute Value-own Price Elasticity-bulk Class
2022	Varies	Basic Net Demand Readjustment Coefficient
2023		Set In Model - Present Net Demand Readjustment Coefficient
2024		Set In Model - Future Net Demand Readjustment Coefficient
2025	0.0	Switch-indicates Additional Project Approval Dates To Follow

D.1.4 Generation And Transmission Projects

no.	description
1	Kootenay Canal(1-2)
2	Kootenay Canal(3-4)
3	Mica(1-2)
4	Mica(3)
5	Mica(4)
6	Site One(1-3)
7	Site One(4)
8	Seven Mile(1-3)
9	Revelstoke(1-2)
10	Revelstoke(3)
11	Revelstoke(4)
12	Kootenay Diversion
13	Shrum(10)
14	McGregor Diversion (without Site C)
15	McGregor Diversion (with Site C)
16	Mica(5)
17	Mica(6)
18	Revelstoke(5)
19	Revelstoke(6)
20	Seven Mile(4)
21	Site C(1-2)
22	Site C(3)
23	Site C(4)
31	Vancouver Island Gas Turbines(1)
32	Vancouver Island Gas Turbines(2)
33	Extra Gas Turbines(150 MW)
34	Extra Gas Turbines(300 MW)
35	Extra Gas Turbines(600 MW)
36	Hat Creek(1)
37	Hat Creek(2)
38	Hat Creek(3)
39	Hat Creek(4)
40	Hat Creek(5)
41	Hat Creek(6)
42	Hat Creek(7)
43	Hat Creek(8)
44	East Kootenay(1)
45	East Kootenay(2)

SOME CONVENTIONS:

```
*  DENOTES MULTIPLICATION
X**2  DENOTES 'X SQUARED'
J1L*  DENOTES A ONE-YEAR LAG OPERATION
NTIME  IS THE CALENDAR YEAR, WITH 75 REPRESENTING
               1975, 76 REPRESENTING 1976, AND SO ON.
>=  DENOTES 'GREATER THAN OR EQUAL TO'
<=  DENOTES 'LESS THAN OR EQUAL TO'
K7  DENOTES THE CURRENT SIMULATION YEAR
M9  DENOTES THE TOTAL NUMBER OF SIMULATION YEARS
IF K7=M9  IS READ 'IF THE SIMULATION IS IN ITS
          TERMINAL YEAR'
```

SUBROUTINE POLD1

DETERMINE INTEGRATED ELECTRICITY REQUIREMENTS BASED ON B C HYDRO'S MAY 1975 PLANNING FORECAST

```
A(2023) - CURRENT NET DEMAND ADJUSTMENT COEFFICIENT
  IF NTIME>=76 AND NTIME<=90 THEN A(2023)=
          1.-((RTIME-75.)*(1.-A(2022))/15.)
  IF NTIME<76 THEN A(2023)=1.
  IF NTIME>90 THEN A(2023)=A(2022)

A(2024) - FUTURE NET DEMAND ADJUSTMENT COEFFICIENT
  IF NTIME>=75 AND NTIME<=84 THEN A(2024)=
          1.-((RTIME-69.)*(1.-A(2022))/15.)
  IF NTIME>=85 THEN A(2024)=A(2022)

DRES - RESIDENTIAL DEMAND
  IF NTIME=75 THEN DRES=5600.*A(2023)
  IF NTIME=76 THEN DRES=6100.*A(2023)
  IF NTIME=77 THEN DRES=6700.*A(2023)
  IF NTIME=78 THEN DRES=7500.*A(2023)
  IF NTIME=79 THEN DRES=8400.*A(2023)
  IF NTIME=80 THEN DRES=9200.*A(2023)
  IF NTIME=81 THEN DRES=10000.*A(2023)
  IF NTIME=82 THEN DRES=11000.*A(2023)
  IF NTIME=83 THEN DRES=12000.*A(2023)
  IF NTIME=84 THEN DRES=13100.*A(2023)
  IF NTIME=85 THEN DRES=14500.*A(2023)
  IF NTIME=86 THEN DRES=15800.*A(2023)
  IF NTIME=87 THEN DRES=17000.*A(2023)
  IF NTIME=88 THEN DRES=18300.*A(2023)
  IF NTIME=89 THEN DRES=19700.*A(2023)
  IF NTIME>=90 THEN DRES=21000.*A(2023)
```

```
DGEN - GENERAL CLASS DEMAND
  IF NTIME=75 THEN DGEN=7000.*A(2023)
  IF NTIME=76 THEN DGEN=8100.*A(2023)
  IF NTIME=77 THEN DGEN=9000.*A(2023)
  IF NTIME=78 THEN DGEN=10000.*A(2023)
  IF NTIME=79 THEN DGEN=11100.*A(2023)
  IF NTIME=80 THEN DGEN=12200.*A(2023)
  IF NTIME=81 THEN DGEN=13300.*A(2023)
  IF NTIME=82 THEN DGEN=14400.*A(2023)
  IF NTIME=83 THEN DGEN=15500.*A(2023)
  IF NTIME=84 THEN DGEN=16700.*A(2023)
  IF NTIME=85 THEN DGEN=18000.*A(2023)
  IF NTIME=86 THEN DGEN=19500.*A(2023)
  IF NTIME=87 THEN DGEN=21000.*A(2023)
  IF NTIME=88 THEN DGEN=22500.*A(2023)
  IF NTIME=89 THEN DGEN=24000.*A(2023)
  IF NTIME>=90 THEN DGEN=25500.*A(2023)

DBULK - BULK CLASS DEMAND
  IF NTIME=75 THEN DBULK=7200.*A(2023)
  IF NTIME=76 THEN DBULK=8400.*A(2023)
  IF NTIME=77 THEN DBULK=9500.*A(2023)
  IF NTIME=78 THEN DBULK=10500.*A(2023)
  IF NTIME=79 THEN DBULK=11600.*A(2023)
  IF NTIME=80 THEN DBULK=12800.*A(2023)
  IF NTIME=81 THEN DBULK=14200.*A(2023)
  IF NTIME=82 THEN DBULK=15600.*A(2023)
  IF NTIME=83 THEN DBULK=17300.*A(2023)
  IF NTIME=84 THEN DBULK=18900.*A(2023)
  IF NTIME=85 THEN DBULK=20400.*A(2023)
  IF NTIME=86 THEN DBULK=22200.*A(2023)
  IF NTIME=87 THEN DBULK=24400.*A(2023)
  IF NTIME=88 THEN DBULK=26600.*A(2023)
  IF NTIME=89 THEN DBULK=28900.*A(2023)
  IF NTIME>=90 THEN DBULK=31500.*A(2023)

DIND - COMMERCIAL AND INDUSTRIAL DEMAND
  DIND=DGEN+DBULK

DWKPL - WEST KOOTENAY POWER AND LIGHT'S INCREMENTAL DEMAND
  IF NTIME=75 THEN DWKPL=0.
  IF NTIME=76 THEN DWKPL=0.
  IF NTIME=77 THEN DWKPL=200.*A(2023)
  IF NTIME=78 THEN DWKPL=400.*A(2023)
  IF NTIME=79 THEN DWKPL=700.*A(2023)
  IF NTIME=80 THEN DWKPL=1000.*A(2023)
  IF NTIME=81 THEN DWKPL=1300.*A(2023)
  IF NTIME=82 THEN DWKPL=1700.*A(2023)
  IF NTIME=83 THEN DWKPL=2100.*A(2023)
  IF NTIME=84 THEN DWKPL=2500.*A(2023)
  IF NTIME=85 THEN DWKPL=2800.*A(2023)
  IF NTIME=86 THEN DWKPL=3000.*A(2023)
  IF NTIME=87 THEN DWKPL=3300.*A(2023)
  IF NTIME=88 THEN DWKPL=3600.*A(2023)
  IF NTIME=89 THEN DWKPL=3800.*A(2023)
  IF NTIME>=90 THEN DWKPL=4100.*A(2023)

NOCUST - NUMBER OF ELECTRICITY CUSTOMERS
  IF NTIME=75 THEN NOCUST=859.
  IF NTIME=76 THEN NOCUST=898.
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  IF NTIME=77 THEN NOCUST=939.
  IF NTIME=78 THEN NOCUST=982.
  IF NTIME=79 THEN NOCUST=1027.
  IF NTIME=80 THEN NOCUST=1074.
  IF NTIME=81 THEN NOCUST=1123.
  IF NTIME=82 THEN NOCUST=1175.
  IF NTIME=83 THEN NOCUST=1229.
  IF NTIME=84 THEN NOCUST=1285.
  IF NTIME=85 THEN NOCUST=1343.
  IF NTIME=86 THEN NOCUST=1405.
  IF NTIME=87 THEN NOCUST=1469.
  IF NTIME=88 THEN NOCUST=1536.
  IF NTIME=89 THEN NOCUST=1607.
  IF NTIME>=90 THEN NOCUST=1680.

DRESF - EXPECTED RESIDENTIAL DEMAND SIX YEARS HENCE
  IF NTIME=75 THEN DRESF=10000.*A(2024)
  IF NTIME=76 THEN DRESF=11000.*A(2024)
  IF NTIME=77 THEN DRESF=12000.*A(2024)
  IF NTIME=78 THEN DRESF=13100.*A(2024)
  IF NTIME=79 THEN DRESF=14500.*A(2024)
  IF NTIME=80 THEN DRESF=15800.*A(2024)
  IF NTIME=81 THEN DRESF=17000.*A(2024)
  IF NTIME=82 THEN DRESF=18300.*A(2024)
  IF NTIME=83 THEN DRESF=19700.*A(2024)
  IF NTIME>=84 THEN DRESF=21000.*A(2024)

DGENF - EXPECTED GENERAL DEMAND SIX YEARS HENCE
  IF NTIME=75 THEN DGENF=13300.*A(2024)
  IF NTIME=76 THEN DGENF=14400.*A(2024)
  IF NTIME=77 THEN DGENF=15500.*A(2024)
  IF NTIME=78 THEN DGENF=16700.*A(2024)
  IF NTIME=79 THEN DGENF=18000.*A(2024)
  IF NTIME=80 THEN DGENF=19500.*A(2024)
  IF NTIME=81 THEN DGENF=21000.*A(2024)
  IF NTIME=82 THEN DGENF=22500.*A(2024)
  IF NTIME=83 THEN DGENF=24000.*A(2024)
  IF NTIME>=84 THEN DGENF=25500.*A(2024)

DBULKF - EXPECTED BULK DEMAND SIX YEARS HENCE
  IF NTIME=75 THEN DBULKF=14200.*A(2024)
  IF NTIME=76 THEN DBULKF=15600.*A(2024)
  IF NTIME=77 THEN DBULKF=17300.*A(2024)
  IF NTIME=78 THEN DBULKF=18900.*A(2024)
  IF NTIME=79 THEN DBULKF=20400.*A(2024)
  IF NTIME=80 THEN DBULKF=22200.*A(2024)
  IF NTIME=81 THEN DBULKF=24400.*A(2024)
  IF NTIME=82 THEN DBULKF=26600.*A(2024)
  IF NTIME=83 THEN DBULKF=28900.*A(2024)
  IF NTIME>=84 THEN DBULKF=31500.*A(2024)

DWKPL - EXPECTED WKPL DEMAND SIX YEARS HENCE
  IF NTIME=75 THEN DWKPLF=1300.*A(2024)
  IF NTIME=76 THEN DWKPLF=1700.*A(2024)
  IF NTIME=77 THEN DWKPLF=2100.*A(2024)
  IF NTIME=78 THEN DWKPLF=2500.*A(2024)
  IF NTIME=79 THEN DWKPLF=2800.*A(2024)
  IF NTIME=80 THEN DWKPLF=3000.*A(2024)
  IF NTIME=81 THEN DWKPLF=3300.*A(2024)
  IF NTIME=82 THEN DWKPLF=3600.*A(2024)
```

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  IF NTIME=83 THEN DWKPLF=3800.*A(2024)
  IF NTIME>=84 THEN DWKPLF=4100.*A(2024)




SUBROUTINE POLS1



SENERBC - BURRARD'S ENERGY CAPABILITY
  SENERBAC=5520.

SET APPROVAL DATE FOR MAJOR GENERATION AND TRANSMISSION PROJECTS
  STARG1=75.
  STARG2=76.
  STARG3=75.
  STARG4=77.
  STARG5=78.
  STARG6=75.
  STARG7=76.
  STARG8=75.
  START1=75.
  START2=76.
  START3=75.
  START4=77.
  START6=75.
  START8=75.
  IF A(2025) NOT= 1. THEN GO TO 5

HERE TO SET APPROVAL DATES FOR REVELSTOKE AND HAT CREEK I
  STARG9=76.
  STARG10=78.
  STARG11=79.
  STARG36=78.
  STARG37=81.
  STARG38=81.
  STARG39=83.
  START9=76.
  START10=78.
  START36=78.
  START38=81.
5 IF NTIME>75 THEN GO TO 10

INCORPORATE REAL CAPITAL COST ADJUSTMENT
  A(1906)=A(1906)*A(1880)
  A(1907)=A(1907)*A(1880)
  A(1908)=A(1908)*A(1880)
  A(1909)=A(1909)*A(1880)
  A(1910)=A(1910)*A(1880)
  A(1911)=A(1911)*A(1880)
  A(1912)=A(1912)*A(1880)
  A(1913)=A(1913)*A(1880)
  A(1914)=A(1914)*A(1880)
  A(1915)=A(1915)*A(1880)
  A(1916)=A(1916)*A(1880)
  A(1917)=A(1917)*A(1880)
  A(1918)=A(1918)*A(1880)
  A(1919)=A(1919)*A(1880)
```

```
  A(1920)=A(1920)*A(1880)
  A(1921)=A(1921)*A(1880)
  A(1922)=A(1922)*A(1880)
  A(1923)=A(1923)*A(1880)
  A(1931)=A(1931)*A(1880)
  A(1932)=A(1932)*A(1880)
  A(1936)=A(1936)*A(1880)
  A(1937)=A(1937)*A(1880)
  A(1938)=A(1938)*A(1880)
  A(1939)=A(1939)*A(1880)
  A(1940)=A(1940)*A(1880)
  A(1941)=A(1941)*A(1880)
  A(1942)=A(1942)*A(1880)
  A(1943)=A(1943)*A(1880)
  A(1944)=A(1944)*A(1880)
  A(1945)=A(1945)*A(1880)

REAL COST ADJUSTMENTS ($76)

HYDRO - ANNUAL FIXED COSTS DUE TO WAGE INCREASES
10 A(1853)=.003+((A(1853)-.003)*A(1881))

COAL - ANNUAL FIXED COSTS (WAGE INCREASES)
  A(1854)=.006+((A(1854)-.006)*A(1881))

GAS TURBINE - ANNUAL FIXED COSTS (WAGE INCREASES)
  A(1855)=.0045+((A(1855)-.0045)*A(1881))

TRANSMISSION AND TRANSFORMATION - ANNUAL FIXED COSTS (WAGE INCREASES)
  A(1856)=.003+((A(1856)-.003)*A(1881))

DISTRIBUTION - ANNUAL FIXED COSTS (WAGE INCREASES)
  A(1857)=.002+((A(1857)-.002)*A(1881))

COAL - ANNUAL VARIABLE COSTS DUE TO ENERGY VALUE INCREASES
  A(1862)=A(1862)*A(1882)
  A(1863)=A(1863)*A(1882)

GAS/OIL - ANNUAL VARIABLE COSTS (ENERGY INCREASES)
  A(1864)=A(1864)*A(1883)
  A(1865)=A(1865)*A(1883)



SUBROUTINE DEMAND



DEMAND EQUATIONS



DRES - RESIDENTIAL DEMAND, PRICE ADJUSTED
  IF A(2012) NOT= 1. THEN GO TO 2
  IF NTIME<77 THEN GO TO 2

  IF NTIME=77 THEN DRES=
         (1.-.2*(1.-RESRED))*DRES
```

```
  IF NTIME=78 THEN DRES=
          (1.-.4*(1.-RESRED))*DRES

  IF NTIME=79 THEN DRES=
          (1.-.6*(1.-RESRED))*DRES

  IF NTIME=80 THEN DRES=
          (1.-.8*(1.-RESRED))*DRES

  IF NTIME>=81 THEN DRES=
          (1.-1.*(1.-RESRED))*DRES
  GO TO 3

2 DRES=DRES

3 IF RTIME=76. THEN DRES=DRES+A(1888)

DGEN - GENERAL CLASS DEMAND, PRICE ADJUSTED
  IF A(2012) NOT= 1. THEN GO TO 4
  IF NTIME<77 THEN GO TO 4

  IF NTIME=77 THEN DGEN=
          (1.-.2*(1.-GENRED))*DGEN

  IF NTIME=78 THEN DGEN=
          (1.-.4*(1.-GENRED))*DGEN

  IF NTIME=79 THEN DGEN=
          (1.-.6*(1.-GENRED))*DGEN

  IF NTIME=80 THEN DGEN=
          (1.-.8*(1.-GENRED))*DGEN

  IF NTIME>=81 THEN DGEN=
          (1.-1.*(1.-GENRED))*DGEN
  GO TO 5

4 DGEN=DGEN

DBULK - BULK DEMAND, PRICE ADJUSTED
5 IF A(2012) NOT= 1. THEN GO TO 6
  IF NTIME<77 THEN GO TO 6

  IF NTIME=77 THEN DBULK=
          (1.-.2*(1.-BULKRED))*DBULK

  IF NTIME=78 THEN DBULK=
          (1.-.4*(1.-BULKRED))*DBULK

  IF NTIME=79 THEN DBULK=
          (1.-.6*(1.-BULKRED))*DBULK

  IF NTIME=80 THEN DBULK=
          (1.-.8*(1.-BULKRED))*DBULK

  IF NTIME>=81 THEN DBULK=
          (1.-1.*(1.-BULKRED))*DBULK
  GO TO 7

6 DBULK=DBULK
```

```
DIND - COMMERCIAL AND INDUSTRIAL DEMAND

7 DIND=DGEN+DBULK

HERE IF DEMAND SHOCK INTRODUCED

  IF RTIME>=A(1887) THEN DIND=DIND+A(1866)

 DWKPL - WEST KOOTENAY POWER AND LIGHT'S INCREMENTAL DEMAND

  DWKPL=DWKPL

 NOCUST - NUMBER OF ELECTRICITY CUSTOMERS

  IF RTIME<76. THEN NOCUST=NOCUST

  IF RTIME>=76. THEN NOCUST=NOCUST+A(1889)

DTOT - TOTAL DEMAND NET OF LOSSES

  DTOT=DRES+DIND+DWKPL

DLOSS - LOSSES ON INTEGRATED SYSTEM

  DLOSS=.2527+.1107*DTOT

DGROSS - TOTAL DEMAND INCLUDING LOSSES

  DGROSS=DTOT+DLOSS

A(1886) - SET GROSS DEMAND SHOCK
  A(1886)=1.1107*A(1866)

DPEAK - MAXIMUM ONE-HOUR DEMAND
  IF A(1885)=0. THEN GO TO 10

  IF RTIME<A(1887) THEN DPEAK=DGROSS/(A(1849)*.0876)

  IF RTIME>=A(1887) THEN DPEAK=(DGROSS-A(1886))/
          (A(1849)*.0876)+A(1886)/(A(1885)*.0876)
  GO TO 20

HERE IF DEMAND SHOCK HAS NO EFFECT ON PEAK DEMAND

10 IF RTIME<A(1887) THEN DPEAK=DGROSS/(A(1849)*.0876)

  IF RTIME>=A(1887) THEN DPEAK=(DGROSS-A(1886))/
          (A(1849)*.0876)

PEXOG - FUTURE PRICE LEVELS
  IF NTIME=75 THEN PEXOG=1.83
  IF NTIME=75 THEN J1L*PEXOG=1.67
  IF NTIME=75 THEN J2L*PEXOG=1.5
  IF NTIME=75 THEN J3L*PEXOG=1.4
  IF NTIME=76 THEN PEXOG=2.11
  IF NTIME=76 THEN J2L*PEXOG=1.67
  IF NTIME=76 THEN J3L*PEXOG=1.5
  IF NTIME=77 THEN PEXOG=2.32
  IF NTIME=77 THEN J3L*PEXOG=1.67
  IF NTIME=78 THEN PEXOG=2.55
```

```
  IF NTIME=79 THEN PEXOG=2.81
  IF NTIME=80 THEN PEXOG=3.09
  IF NTIME>=81 THEN PEXOG=1.05*J1L*PEXOG

A(1972) - SET RATE OF INFLATION
  A(1972)=(PEXOG/J1L*PEXOG)-1.

INTRED$H - REDUCTIONS IN INTEREST CHARGES DUE TO MATURING
            OF BONDS ISSUED BEFORE 1976
  IF NTIME=75 THEN INTRED$H=0.
  IF NTIME=76 THEN INTRED$H=.97
  IF NTIME=77 THEN INTRED$H=2.61
  IF NTIME=78 THEN INTRED$H=0.
  IF NTIME=79 THEN INTRED$H=.72
  IF NTIME=80 THEN INTRED$H=5.22
  IF NTIME=81 THEN INTRED$H=5.64
  IF NTIME=82 THEN INTRED$H=15.16
  IF NTIME=83 THEN INTRED$H=0.
  IF NTIME=84 THEN INTRED$H=4.31
  IF NTIME=85 THEN INTRED$H=4.31
  IF NTIME=86 THEN INTRED$H=5.26
  IF NTIME=87 THEN INTRED$H=5.49
  IF NTIME=88 THEN INTRED$H=8.2
  IF NTIME=89 THEN INTRED$H=10.33
  IF NTIME=90 THEN INTRED$H=1.42

LOLDM$H - STOCK OF DEBT ISSUED PRIOR TO 1976 THAT MATURES
            EACH YEAR
  IF NTIME=75 THEN LOLDM$H=0.
  IF NTIME=76 THEN LOLDM$H=29.4
  IF NTIME=77 THEN LOLDM$H=50.1
  IF NTIME=78 THEN LOLDM$H=0.
  IF NTIME=79 THEN LOLDM$H=18.4
  IF NTIME=80 THEN LOLDM$H=59.1
  IF NTIME=81 THEN LOLDM$H=67.9
  IF NTIME=82 THEN LOLDM$H=187.3
  IF NTIME=83 THEN LOLDM$H=0.
  IF NTIME=84 THEN LOLDM$H=50.
  IF NTIME=85 THEN LOLDM$H=50.
  IF NTIME=86 THEN LOLDM$H=124.4
  IF NTIME=87 THEN LOLDM$H=105.4
  IF NTIME=88 THEN LOLDM$H=156.3
  IF NTIME=89 THEN LOLDM$H=155.3
  IF NTIME=90 THEN LOLDM$H=21.9

LMATWOSF - SHORTFALL IN SINKING FUND FOR BONDS MATURING AFTER 1981
  LMATWOSF=0.
  IF NTIME=82 THEN LMATWOSF=93.2
  IF NTIME=86 THEN LMATWOSF=104.2
  IF NTIME=87 THEN LMATWOSF=60.3
  IF NTIME=88 THEN LMATWOSF=81.9
  IF NTIME=89 THEN LMATWOSF=104.8
  IF NTIME=90 THEN LMATWOSF=9.2

COVERAGE - INTEREST COVERAGE POLICY COEFFICIENT
  IF NTIME=75 THEN COVERAGE=0.
  IF NTIME=76 THEN COVERAGE=0.
  IF NTIME=77 THEN COVERAGE=.04
  IF NTIME=78 THEN COVERAGE=.08
  IF NTIME=79 THEN COVERAGE=.12
```

```
  IF NTIME=80 THEN COVERAGE=.16
  IF NTIME=81 THEN COVERAGE=.2
  IF NTIME=82 THEN COVERAGE=.24
  IF NTIME=83 THEN COVERAGE=.28
  IF NTIME>=84 THEN COVERAGE=.3

RESRED - RES. DEMAND CHANGE DUE TO MARG. PRICE CHANGE
  RESRED=(A(2013)+A(2014)-(A(2019)*(A(2014)-A(2013))))/
         (A(2019)*(A(2014)-A(2013))+A(2013)+A(2014))

GENRED - GENERAL DEMAND CHANGE DUE TO MARGINAL PRICE CHANGE
  GENRED=(A(2015)+A(2016)-(A(2020)*(A(2016)-A(2015))))/
         (A(2020)*(A(2016)-A(2015))+A(2015)+A(2016))

BULK DEMAND CHANGE DUE TO MARGINAL PRICE CHANGE
  BULKRED=(A(2017)+A(2018)-(A(2021)*(A(2018)-A(2017))))/
         (A(2021)*(A(2018)-A(2017))+A(2017)+A(2018))

TOTRED - WEIGHTED DEMAND CHANGE DUE TO MARGINAL PRICE CHANGE
  TOTRED=((RESRED*DRES)+(GENRED*DGEN)+
         (BULKRED*DBULK))/(DRES+DGEN+DBULK)




SUBROUTINE MCOST



CHECK FOR CRITICAL RAINFALL PERIOD
  IF A(2007) NOT= 0. THEN GO TO 20

SENERC - TOTAL NEW ENERGY GENERATION CAPABILITY DURING AVERAGE
            RAINFALL PERIOD
  SENERC=SENERHAC+SENERBAC+SENERCAC+SENERKAC+SENERGAC-
                                796.
  GO TO 40

SENERC - TOTAL NEW ENERGY GENERATION CAPABILITY DURING
            CRITICAL RAINFALL PERIOD
20 SENERC=SENERHCC+SENERBAC+SENERCAC+SENERKAC+SENERGAC-
                                                   9.

SCAP - TOTAL NEW CAPACITY CAPABILITY
40 SCAP=SCAPH+SCAPB+SCAPC+SCAPK+SCAPG-5413.
  IF A(2010)>30. THEN GO TO 50
  IF A(2011)>10. THEN GO TO 50

HERE IF A HYDRO PROJECT

NLIFE - EXPECTED PHYSICAL LIFE OF PROJECT
  NLIFE=70

COP$76 - ANNUAL OPERATING COSTS OF PROJECT ($76)

  COP$76=A(1853)*KPISH$76+A(1856)*KPST1$76+
         A(1861)*SENERC+A(1860)*SCAP
  GO TO 100
50 IF A(2010)>35. THEN GO TO 60
```

```
      IF A(2011)>15. THEN GO TO 60

    HERE IF A GAS TURBINE PROJECT

      COP$76=A(1855)*KPISG$76+A(1856)*KPST1$76+A(1865)*
              SENERC
      GO TO 90
   60 IF A(2010)>43. THEN GO TO 70
      IF A(2011)>20. THEN GO TO 70

    HERE IF HAT CREEK COAL

      COP$76=A(1854)*KPISC$76+A(1856)*KPST1$76+A(1862)*
              SENERC
      GO TO 90

    HERE IF EAST KOOTENAY COAL

   70 COP$76=A(1854)*KPISK$76+A(1856)*KPST1$76+A(1863)*
              SENERC
   90 NLIFE=35
  100 RLIFE=NLIFE

    QSTART EQUAL 1 IF NEW PROJECT IS PRODUCING ENERGY
      IF (SENERC+SCAP)>0. THEN QSTART=1.

    NSTOP - TIME WHEN PROJECT'S LIFE IS OVER
      IF (QSTART-J1L*QSTART)=1. THEN NSTOP=NTIME+NLIFE-75

      IF K7>NSTOP THEN COP$76=0.

    RSTART - TIME WHEN NEW PROJECT BEGINS PRODUCING ENERGY
      IF QSTART=0. THEN RSTART=0.
      IF (QSTART-J1L*QSTART)=1. THEN RSTART=RTIME

    KPVELEC1 - PRESENT VALUE OF POTENTIAL ENERGY PRODUCED (KWH) DURING
                LIFE OF PROJECT BEING ANALYZED

      KPVELEC1=(1.+A(1894))*J1L*KPVELEC1+SENERC*((1.+A(1894))**.5)

    KPVELEC2 - PRESENT VALUE OF POTENTIAL CAPACITY GENERATED(MW) DURING
                LIFE OF PROJECT BEING ANALYZED

      KPVELEC2=(1.+A(1894))*J1L*KPVELEC2+SCAP*((1.+A(1894))**.5)
      IF QSTART=0. THEN GO TO 110

      IF K7=NSTOP THEN KPVELEC1=KPVELEC1/((1.+A(1894))**(K7-2))

      IF K7>NSTOP THEN KPVELEC1=0.

      IF K7=NSTOP THEN KPVELEC2=KPVELEC2/((1.+A(1894))**(K7-2))

      IF K7>NSTOP THEN KPVELEC2=0.

    DETERMINE TYPE OF DEPRECIATION BEING USED
  110 IF A(1850)>=1. THEN GO TO 120

    HERE IF EXPONENTIALLY DECLINING DEPRECIATION CHARGE BASED ON
                AVERAGE ECONOMY-WIDE SERVICE LIFE
```

```
  KELEC=(J1L*KELEC+IGEN$76+ITRS1$76)*
           (1.-(QSTART*A(1850)))

 KPVC1$76 - PRESENT VALUE OF COSTS ASSOCIATED WITH PROJECT BEING
              ANALYZED

  KPV1$76=(1.+A(1894))*J1L*KPV1$76+(COP$76+(A(1850)*
           (J1L*KELEC+IGEN$76+ITRS1$76))+
           ((A(1890)+A(1895))*.5*(J1L*KELEC+KELEC)))*
           ((1.+A(1894))**.5)
  GO TO 200

 HERE IF STRAIGHT-LINE DEPRECIATION CHARGE BASED ON ACTUAL LIFE OF
              PROJECT BEING ANALYZED
120 IF A(1850)=1. THEN A(1850)=RLIFE
  IF RSTART=0. THEN GO TO 125
  IF A(1850)<=(RTIME-RSTART) THEN GO TO 130

125 KELEC=(J1L*KELEC+IGEN$76+ITRS1$76)*
           (1.-(QSTART/(A(1850)-(RTIME-RSTART))))

  KPV1$76=(1.+A(1894))*J1L*KPV1$76+(COP$76+(QSTART/
           (A(1850)-(RTIME-RSTART))*(J1L*KELEC+IGEN$76+ITRS1$76))+
           ((A(1890)+A(1895))*.5*(J1L*KELEC+KELEC)))*
           ((1.+A(1894))**.5)
  GO TO 200

 HERE IF PROJECT LIFE FOR DEPRECIATION PURPOSES IS OVER

130 KELEC=0.

  KPV1$76=(1.+A(1894))*J1L*KPV1$76+
           (COP$76+((A(1890)+A(1895))*.5*(J1L*KELEC+KELEC)))*
           ((1.+A(1894))**.5)
200 IF QSTART=0. THEN GO TO 210

  IF K7=NSTOP THEN KPV1$76=KPV1$76/((1.+A(1894))**(K7-2))

  IF K7>NSTOP THEN KPV1$76=0.

 PKWHCST1 - 1976$ PRESENT VALUE COST PER KWH ENERGY CAPACITY FOR
              PROJECT BEING ANALYZED

  IF K7=NSTOP THEN PKWHCST1=KPV1$76/KPVELEC1

  IF K7>NSTOP THEN PKWHCST1=0.

 PWCOST1 - 1976$ PRESENT VALUE COST PER WATT CAPACITY CAPABILITY
              FOR PROJECT BEING ANALYZED

  IF K7=NSTOP THEN PWCOST1=KPV1$76/KPVELEC2

  IF K7>NSTOP THEN PWCOST1=0.
```

```
THIS SECTION SETS APPROVAL DATES FOR PRESENTLY UNCOMMITTED MAJOR
            GENERATION AND TRANSMISSION PROJECTS BY COMPARING
            EXPECTED ENERGY AND CAPACITY REQUIREMENTS
            WITH PRESENTLY COMMITTED ENERGY AND CAPACITY
            CAPABILITY. ENERGY AND/OR CAPACITY IS BROUGHT ON
            STREAM IN AN INCREASING COST SEQUENCE TO MEET THIS
            ANTICIPATED DEMAND.



DTOTF

  DTOTF=DTOTF

DGROSSF

  DGROSSF=DGROSSF

DPEAKF

  DPEAKF=DPEAKF

HERE IF RATE STRUCTURE CHANGE AFFECTS DTOTF
  IF A(2012)=1. THEN DTOTF=RESRED*DRESF+
          GENRED*DGENF+BULKRED*DBULKF+DWKPLF
  IF A(2012) NOT= 1. THEN DTOTF=DRESF+DGENF+DBULKF+
          DWKPLF

DTOTF - ADJUST EXPECTED TOTAL NET DEMAND BY DEMAND SHOCK
  IF RTIME>=(A(1887)-6.) THEN DTOTF=DTOTF+A(1866)

DGROSSF - APPLY LOSS FACTOR TO DETERMINE TOTAL GROSS DEMAND
            SIX YEARS HENCE
  DGROSSF=DTOTF+.2527+(.1107*DTOTF)

A(1886) - SET GROSS DEMAND SHOCK
  A(1886)=1.1107*A(1866)

DPEAKF - EXPECTED PEAK DEMAND SIX YEARS HENCE DERIVED FROM LOAD FACTOR
            APPLIED TO EXPECTED DEMAND
  IF A(1885)=0. THEN GO TO 1
  IF RTIME<(A(1887)-6.) THEN DPEAKF=DGROSSF/
          (A(1849)*.0876)
  IF RTIME>=(A(1887)-6.) THEN DPEAKF=(DGROSSF-A(1886))/
          (A(1849)*.0876)+A(1886)/(A(1885)*.0876)
  GO TO 2

HERE IF DEMAND SHOCK HAS NO EFFECT ON PEAK DEMAND
1 IF RTIME<(A(1887)-6.) THEN DPEAKF=DGROSSF/
          (A(1849)*.0876)
  IF RTIME>=(A(1887)-6.) THEN DPEAKF=(DGROSSF-A(1886))/
          (A(1849)*.0876)

CARRY FORWARD APPROVAL DATES FOR EACH PROJECT
2 DO 3 I=429,470
3 STARG?=J1L*STARG?
  DO 4 I=477,485
4 START?=J1L*START?
```

```
SECNEW - INITIALIZE NEW ENERGY CAPACITY VARIABLE
  SECNEW=0.

SENCAPF - EXPECTED ENERGY GENERATION CAPACITY SIX YEARS HENCE ON

BASIS OF PROJECTS APPROVED TO DATE
  IF NTIME=75 THEN SENCAPF=41349.
  IF NTIME>75 THEN SENCAPF=J1L*SENCAPF+(.5*J1L*SECNEW)

SCAPF - EXPECTED CAPACITY CAPABILITY SIX YEARS HENCE ON BASIS
            OF PROJECTS APPROVED TO DATE
  IF NTIME=75 THEN SCAPF=8488.
  IF NTIME>75 THEN SCAPF=J1L*SCAPF

SEE IF DEMAND IS AT THE LEVEL REQUIRING INSTALLATION OF GAS
            TURBINES ON VANCOUVER ISLAND
  IF J1L*DTOTF>37000. THEN GO TO 5
  IF DTOTF<37000. THEN GO TO 10
  STARG31=RTIME+5.
  START31=RTIME+4.
  SECNEW=SECNEW+657.
  SENCAPF=SENCAPF+(.5*657.)
  SCAPF=SCAPF+150.
5 IF J1L*DTOTF>41000. THEN GO TO 10
  IF DTOTF<41000. THEN GO TO 10
  STARG32=RTIME+5.
  SECNEW=SECNEW+657.
  SENCAPF=SENCAPF+(.5*657.)
  SCAPF=SCAPF+150.

SET APPROVAL DATES FOR VARIOUS INCREASINGLY COSTLY ENERGY
            GENERATION AND ASSOCIATED TRANSMISSION PROJECTS BASED ON
            COMPARING EXPECTED ENERGY GENERATION CAPACITY (FROM PREV-
            IOUSLY APPROVED PROJECTS) DURING CRITICAL RAINFALL PERIODS
            WITH EXPECTED GROSS ENERGY DEMAND LEVELS, AND ADJUSTING TO
            INCORPORATE THE DIFFERENT CONSTRUCTION PERIODS REQUIRED.
10 IF NTIME NOT= 78 THEN GO TO 20
  STARG12=RTIME+4.
  SECNEW=SECNEW+875.
  SENCAPF=SENCAPF+(.5*875.)
20 IF SENCAPF>=DGROSSF THEN GO TO 500
  IF NTIME<=78 THEN GO TO 30
  IF STARG14>0. THEN GO TO 30
  STARG14=RTIME
  SECNEW=SECNEW+2750.
  SENCAPF=SENCAPF+(.5*2750.)
  IF SENCAPF>=DGROSSF THEN GO TO 500
30 IF STARG9>0. THEN GO TO 40
  STARG9=RTIME
  START9=RTIME
  SECNEW=SECNEW+4773.
  SENCAPF=SENCAPF+(.5*4773.)
  SCAPF=SCAPF+900.
  IF SENCAPF>=DGROSSF THEN GO TO 500
40 IF STARG10>0. THEN GO TO 50
  STARG10=RTIME+1.
  IF STARG10>(STARG9+2.) THEN STARG10=STARG9+2.
  START10=STARG10
  SECNEW=SECNEW+1634.
  SENCAPF=SENCAPF+(.5*1634.)
```

```
      SCAPF=SCAPF+450.
      IF SENCAPF>=DGROSSF THEN GO TO 500
   50 IF STARG11>0. THEN GO TO 60
      STARG11=RTIME+2.
      SECNEW=SECNEW+484.
      IF STARG11>(STARG10+1.) THEN STARG11=STARG10+1.
      SENCAPF=SENCAPF+(.5*484.)
      SCAPF=SCAPF+450.
      IF SENCAPF>=DGROSSF THEN GO TO 500
   60 IF STARG36>0. THEN GO TO 70
      STARG36=RTIME
      START36=RTIME
      SECNEW=SECNEW+3420.
      SENCAPF=SENCAPF+(.5*3420.)
      SCAPF=SCAPF+500.
      IF SENCAPF>=DGROSSF THEN GO TO 500
   70 IF STARG37>0. THEN GO TO 80
      STARG37=RTIME+1.
      SECNEW=SECNEW+3420.
      SENCAPF=SENCAPF+(.5*3420.)
      SCAPF=SCAPF+500.
      IF SENCAPF>=DGROSSF THEN GO TO 500
   80 IF STARG38>0. THEN GO TO 90
      STARG38=RTIME+1.
      START38=RTIME+1.
      SECNEW=SECNEW+3420.
      SENCAPF=SENCAPF+(.5*3420.)
      SCAPF=SCAPF+500.
      IF SENCAPF>=DGROSSF THEN GO TO 500
   90 IF STARG39>0. THEN GO TO 130
      STARG39=RTIME+1.
      SECNEW=SECNEW+3420.
      SENCAPF=SENCAPF+(.5*3420.)
      SCAPF=SCAPF+500.
      IF SENCAPF>=DGROSSF THEN GO TO 500
  130 IF STARG40>0. THEN GO TO 140
      STARG40=RTIME
      START40=RTIME
      SECNEW=SECNEW+4790.
      SENCAPF=SENCAPF+(.5*4790.)
      SCAPF=SCAPF+700.
      IF SENCAPF>=DGROSSF THEN GO TO 500
  140 IF STARG41>0. THEN GO TO 150
      STARG41=RTIME+1.
      SECNEW=SECNEW+4790.
      SENCAPF=SENCAPF+(.5*4790.)
      SCAPF=SCAPF+700.
      IF SENCAPF>=DGROSSF THEN GO TO 500
  150 IF STARG42>0. THEN GO TO 160
      STARG42=RTIME+1.
      SECNEW=SECNEW+4790.
      SENCAPF=SENCAPF+(.5*4790.)
      SCAPF=SCAPF+700.
      IF SENCAPF>=DGROSSF THEN GO TO 500
  160 IF STARG43>0. THEN GO TO 170
      STARG43=RTIME+1.
      SECNEW=SECNEW+4790.
      SENCAPF=SENCAPF+(.5*4790.)
      SCAPF=SCAPF+700.
      IF SENCAPF>=DGROSSF THEN GO TO 500
```

```
170 IF STARG46>0. THEN GO TO 180
    STARG46=RTIME
    START44=RTIME
    SECNEW=SECNEW+4790.
    SENCAPF=SENCAPF+(.5*4790.)
    SCAPF=SCAPF+700.
    IF SENCAPF>=DGROSSF THEN GO TO 500
180 IF STARG45>0. THEN GO TO 190
    STARG45=RTIME
    START45=RTIME+2.
    SECNEW=SECNEW+4790.
    SENCAPF=SENCAPF+(.5*4790.)
    SCAPF=SCAPF+700.
    IF SENCAPF>=DGROSSF THEN GO TO 500
190 IF STARG21>0. THEN GO TO 200
    STARG21=RTIME
    START21=RTIME+2.
    SECNEW=SECNEW+2702.
    SENCAPF=SENCAPF+(.5*2702.)
    SCAPF=SCAPF+450.
    IF SENCAPF>=DGROSSF THEN GO TO 500
200 IF STARG22>0. THEN GO TO 210
    STARG22=RTIME+2.
    IF STARG22>(STARG21+3.) THEN STARG22=
            STARG21+3.
    SECNEW=SECNEW+1143.
    SENCAPF=SENCAPF+(.5*1143.)
    SCAPF=SCAPF+225.
    IF SENCAPF>=DGROSSF THEN GO TO 500
210 IF STARG23>0. THEN GO TO 500
    STARG23=RTIME+2.
    IF STARG23>STARG22 THEN STARG23=STARG22
    SECNEW=SECNEW+613.
    SENCAPF=SENCAPF+(.5*613.)
    SCAPF=SCAPF+225.

  RESMARD - DETERMINE DESIRED RESERVE CAPACITY MARGIN SIX YEARS
              HENCE BASED ON LOSS-OF-LOAD PROBABILITY METHOD RESULTS FOR
              EXPECTED NATURE OF GENERATION SYSTEM
500 IF STARG36=0. THEN RESMARDF=.09
    IF STARG36>0. THEN RESMARDF=.10
    IF STARG37>0. THEN RESMARDF=.11
    IF STARG38>0. THEN RESMARDF=.115
    IF STARG39>0. THEN RESMARDF=.12
    IF STARG40>0. THEN RESMARDF=.125
    IF STARG41>0. THEN RESMARDF=.1325
    IF STARG42>0. THEN RESMARDF=.14
    IF STARG46>0. THEN RESMARDF=.145

 SCAPDF - DESIRED CAPACITY CAPABILITY SIX YEARS HENCE
    SCAPDF=DPEAKF*(1.+RESMARDF)

  SET APPROVAL DATES FOR VARIOUS INCREASINGLY COSTLY CAPACITY-PROD-
              UCING PROJECTS BASED ON COMPARING EXPECTED CAPACITY
              CAPABILITY FROM PREVIOUSLY APPROVED PROJECTS WITH
              EXPECTED DESIRED CAPACITY, AND ADJUSTING TO INCORPORATE
              THE VARYING CONSTRUCTION PERIODS.
    IF SCAPF>=SCAPDF THEN GO TO 1000
    IF STARG13>0. THEN GO TO 510
    STARG13=RTIME+3.
```

```
      SCAPF=SCAPF+275.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 510  IF STARG16>0. THEN GO TO 520
      STARG16=RTIME+2.
      SCAPF=SCAPF+400.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 520  IF STARG17>0. THEN GO TO 530
      STARG17=RTIME+2.
      SCAPF=SCAPF+400.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 530  IF STARG18>0. THEN GO TO 540
      STARG18=RTIME+2.
      SCAPF=SCAPF+450.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 540  IF STARG19>0. THEN GO TO 550
      STARG19=RTIME+2.
      SCAPF=SCAPF+450.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 550  IF STARG20>0. THEN GO TO 560
      STARG20=RTIME+2.
      SECNEW=SECNEW+65.
      SENCAPF=SENCAPF+(.5*65.)
      SCAPF=SCAPF+175.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 560  IF STARG33>0. THEN GO TO 570
      STARG33=RTIME+5.
      SECNEW=SECNEW+657.
      SENCAPF=SENCAPF+(.5*657.)
      SCAPF=SCAPF+150.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 570  IF STARG34>0. THEN GO TO 580
      STARG34=RTIME+5.
      SECNEW=SECNEW+1314.
      SENCAPF=SENCAPF+(.5*1314.)
      SCAPF=SCAPF+300.
      IF SCAPF>=SCAPDF THEN GO TO 1000
 580  IF STARG35>0. THEN GO TO 1000
      STARG35=RTIME+5.
      SECNEW=SECNEW+2628.
      SENCAPF=SENCAPF+(.5*2628.)
      SCAPF=SCAPF+600.
1000  SECNEW=SECNEW


    SUBROUTINE SUPPLY


    THIS SECTION TAKES INFORMATION ON DEMAND GROWTH FORECASTS AND
                DETERMINES THE QUANTITY AND COST OF FACILITIES THAT
                SHOULD BE BUILT


    ITRS2$76 - INVESTMENT IN NON-ASSOCIATED MAJOR TRANSMISSION PROJECTS
      IF NTIME=75 THEN ITRS2$76=15.
      IF NTIME>=76 THEN ITRS2$76=A(2000)*(DPEAK-J1L*DPEAK)
```

```
ITRS3$76 - INVESTMENT IN SUB-TRANSMISSION LINES
  IF NTIME=75 THEN ITRS3$76=10.
  IF NTIME>=76 THEN ITRS3$76=A(2001)*(DPEAK-J1L*DPEAK)

ITRF1$76 - INVESTMENT IN TRANSMISSION TRANSFORMATION
  IF NTIME=75 THEN ITRF1$76=5.
  IF NTIME>=76 THEN ITRF1$76=A(2002)*(DPEAK-J1L*DPEAK)

ITRF2$76 - INVESTMENT IN SUB-TRANSMISSION TRANSFORMATION
  IF NTIME=75 THEN ITRF2$76=20.
  IF NTIME>=76 THEN ITRF2$76=A(2003)*(DPEAK-J1L*DPEAK)

IDST1$76 - INVESTMENT IN DISTRIBUTION FACILITIES FOR NEW CUSTOMERS
  IF NTIME=75 THEN IDST1$76=50.
  IF NTIME>=76 THEN IDST1$76=A(2004)*(NOCUST-J1L*NOCUST)

IDST2$76 - INVESTMENT IN DISTRIBUTION FACILITIES FOR GROWTH BY
             EXISTING CUSTOMERS
  IF NTIME=75 THEN IDST2$76=10.
  IF NTIME>=76 THEN IDST2$76=A(2005)*(DPEAK-J1L*DPEAK)

IMISC$76 - INVESTMENT IN OTHER ELECTRIC PLANT
  IF NTIME=75 THEN IMISC$76=6.
  IF NTIME>=76 THEN IMISC$76=A(2006)*(DTOT-J1L*DTOT)

SET ANY NEGATIVE INVESTMENT TO ZERO
  IF ITRS2$76<0. THEN ITRS2$76=0.
  IF ITRS3$76<0. THEN ITRS3$76=0.
  IF ITRF1$76<0. THEN ITRF1$76=0.
  IF ITRF2$76<0. THEN ITRF2$76=0.
  IF IDST1$76<0. THEN IDST1$76=0.
  IF IDST2$76<0. THEN IDST2$76=0.
  IF IMISC$76<0. THEN IMISC$76=0.

ITRS$74 - INVESTMENT IN MAJOR TRANSMISSION AND SUB-TRANSMISSION
             PROJECTS

  ITRS$76=ITRS1$76+ITRS2$76+ITRS3$76

ITRF$76 - INVESTMENT IN TRANSFORMATION

  ITRF$76=ITRF1$76+ITRF2$76

IDIST$76 - INVESTMENT IN DISTRIBUTION FACILITIES

  IDIST$76=IDST1$76+IDST2$76+IMISC$76

 KPISH$H - NEW HYDRO PLANT IN SERVICE

  KPISH$H=KPISH$H

 KPISC$H - NEW COAL GENERATION PLANT IN SERVICE

  KPISC$H=KPISC$H

 KPISG$H - NEW GAS TURBINES IN SERVICE

  KPISG$H=KPISG$H

KPISTS$H - MAJOR TRANSMISSION AND SUB-TRANSMISSION PLANT IN
```

```
  KPISTS$H=KPIST1$H+KPIST2$H

KPIST$H - TRANSMISSION AND TRANSFORMATION PLANT IN SERVICE ($H)

  KPIST$H=KPIST1$H+KPIST2$H+KPISTF$H

I$ - INVESTMENT IN CURRENT DOLLARS

  I$=IGEN$+ITRS1$+(PEXOG/2.11*(ITRS2$76+
          ITRS3$76+ITRF1$76+ITRF2$76+IDST1$76+IDST2$76+
          IMISC$76))

KPIST2$76 - NEW NON-ASSOCIATED TRANSMISSION AND SUB-TRANSMISSION
               PLANT IN SERVICE ($76)
  KPST2$76=J1L*KPST2$76+ITRS2$76+ITRS3$76

KPSTF$76 - NEW TRANSFORMATION PLANT IN SERVICE ($76)
  KPSTF$76=J1L*KPSTF$76+ITRF1$76+ITRF2$76

KPIST$76 - ALL NEW TRANSMISSION AND TRANSFORMATION PLANT
               IN SERVICE ($76)

  KPIST$76=KPST1$76+KPST2$76+KPSTF$76

KPST3$76 - ALL NEW TRANSMISSION AND TRANSFORMATION PLANT IN
               SERVICE ($76) TO SERVE CUSTOMERS AT THE 230 KV LEVEL
  KPST3$76=J1L*KPST3$76+ITRS2$76+ITRS3$76+ITRF1$76+
          KPST1$76-J1L*KPST1$76

  KPST3$76=KPST3$76

KPST4$76 - STOCK OF NEW SUB-TRANSMISSION TRANSFORMATION PLANT
              IN SERVICE ($76)
  KPST4$76=J1L*KPST4$76+ITRF2$76

KPISD$76 - NEW DISTRIBUTION PLANT IN SERVICE ($76)

  KPISD$76=J1L*KPISD$76+IDST1$76+IDST2$76+IMISC$76

KPISM$76 - NEW MISCELLANEOUS PLANT IN SERVICE ($76) FOR 230 KV
               LEVEL CUSTOMERS

  KPISM$76=J1L*KPISM$76+(.5*IMISC$76)

KPIS$76 - TOTAL NEW PLANT IN SERVICE ($76)

  KPIS$76=KPISH$76+KPISG$76+KPISC$76+KPISK$76+
          KPIST$76+KPISD$76

KPIST2$H - NEW NON-ASSOCIATED MAJOR TRANSMISSION AND SUBTRANS-
               MISSION PLANT IN SERVICE ($H)
  KPIST2$H=J1L*KPIST2$H+(PEXOG/2.11*(ITRS2$76+ITRS3$76)
          *A(1851))

KPISTF$H - NEW TRANSFORMATION PLANT IN SERVICE ($H)

  KPISTF$H=J1L*KPISTF$H+(PEXOG/2.11*(ITRF1$76+
          ITRF2$76)*A(1852))
```

KPISD$H - NEW DISTRIBUTION PLANT IN SERVICE ($H)

```
KPISD$H=J1L*KPISD$H+(PEXOG/2.11*(IDST1$76+IDST2$76+
        IMISC$76))
```

RESMARD - DESIRED RESERVE CAPACITY MARGIN DERIVED FROM LOSS-OF-LOAD PROBABILITY OF ONE DAY IN TEN YEARS

```
IF SCAPH<6100. THEN RESMARD=.10

IF SCAPH>=6100. THEN RESMARD=.095

IF SCAPH>=6400. THEN RESMARD=.09

IF SCAPC>0. THEN RESMARD=.10

IF SCAPC>=500. THEN RESMARD=.105

IF SCAPC>=1000. THEN RESMARD=.11

IF SCAPC>=1500. THEN RESMARD=.115

IF SCAPC>=2000. THEN RESMARD=.12

IF SCAPC>=2500. THEN RESMARD=.125

IF SCAPC>=3000. THEN RESMARD=.13

IF SCAPC>=3500. THEN RESMARD=.135

IF SCAPC>=4000. THEN RESMARD=.14

IF SCAPK>0. THEN RESMARD=.145
```

SCAPD - DESIRED CAPACITY CAPABILITY (INCLUDES DESIRED RESERVE CAPACITY MARGIN)

```
SCAPD=DPEAK*(1.+RESMARD)
```

SCAP - ANNUAL CAPACITY CAPABILITY

```
SCAP=SCAPH+SCAPB+SCAPC+SCAPK+SCAPG
```

SCAPSURP - SURPLUS (DEFICIT) OF ACTUAL CAPACITY CAPABILITY OVER DESIRED CAPACITY CAPABILITY

```
SCAPSURP=SCAP-SCAPD
```

RESMAR - ACTUAL RESERVE CAPACITY MARGIN

```
RESMAR=(SCAP-DPEAK)/DPEAK
```

DETERMINE ACTUAL ENERGY PRODUCED FROM EACH SOURCE

SENERH - ACTUAL ENERGY PRODUCED FROM HYDRO SOURCES

```
SENERH=DGROSS
```

```
SENERC - ACTUAL ENERGY PRODUCED FROM HAT CREEK COAL

  SENERC=0.

  IF DGROSS>SENERHC THEN SENERC=DGROSS-SENERHC

  IF DGROSS>(SENERHC+SENERCC) THEN SENERC=SENERCC

SENERK - ACTUAL ENERGY PRODUCED FROM EAST KOOTENAY COAL

  SENERK=0.

  IF DGROSS>(SENERHC+SENERCC) THEN SENERK=DGROSS-
          SENERHC-SENERCC

  IF DGROSS>(SENERHC+SENERCC+SENERKC) THEN SENERK=SENERKC

SENERB - ACTUAL ENERGY PRODUCED AT BURRARD

  SENERB=0.

  IF DGROSS>(SENERHC+SENERCC+SENERKC) THEN SENERB=
          DGROSS-SENERHC-SENERCC-SENERKC

  IF DGROSS>(SENERHC+SENERCC+SENERKC+SENERBC) THEN SENERB=
          SENERBC

SENERG - ACTUAL ENERGY PRODUCED FROM GAS TURBINES

  SENERG=0.

  IF DGROSS>(SENERHC+SENERCC+SENERKC+SENERBC) THEN SENERG=
          DGROSS-SENERHC-SENERCC-SENERKC-SENERBC

  IF DGROSS>(SENERHC+SENERCC+SENERKC+SENERBC+

          SENERGC) THEN  SENERG=SENERGC

SENERM - ACTUAL ENERGY IMPORTED FROM OTHER UTILITIES

  SENERM=0.

  IF DGROSS>(SENERHC+SENERCC+SENERKC+SENERBC+

          SENERGC) THEN  SENERM=DGROSS-SENERHC-SENERCC-SENERKC
          -SENERBC-SENERGC

  IF SENERM>0. THEN GO TO 200

SENEREXP - ACTUAL ENERGY EXPORTED TO OTHER UTILITIES
           B C HYDRO SEEKS TO EXPORT ELECTRICITY WHEN GROSS
           DOMESTIC DEMAND IS LESS THAN ENERGY GENERATION CAPACITY
           AND VARIABLE OPERATING COSTS ARE BELOW EXPORT PRICES.
           THE EXTENT TO WHICH IT FINDS A MARKET FOR ANY
           ECONOMICALLY SURPLUS POWER IS DETERMINED BY THE
           FRACTION SET BY A(1873)
  IF A(1863)>=A(1879) THEN GO TO 100
```

```
    DEXPORT=A(1873)*(SENERHC+SENERCC+SENERKC-DGROSS)

    IF DEXPORT<0. THEN DEXPORT=0.

    IF DEXPORT=0. THEN GO TO 200
    IF A(1862)<A(1879) THEN GO TO 20

    DEXPORT=A(1873)*(SENERHC+SENERKC-DGROSS)

    IF DEXPORT<0. THEN DEXPORT=0.

    IF DEXPORT=0. THEN GO TO 200
    DIFFH=SENERHC-SENERH
    IF DIFFH<=0. THEN GO TO 10

    SENERH=SENERH+DEXPORT

    IF SENERH<SENERHC THEN GO TO 200

    SENERH=SENERHC

    SENERK=SENERK+DEXPORT-DIFFH
    GO TO 200

 10 SENERK=SENERK+DEXPORT
    GO TO 200
 20 DIFFH=SENERHC-SENERH
    DIFFC=SENERCC-SENERC
    IF DIFFH>0. THEN GO TO 30
    IF DIFFC>0. THEN GO TO 40

    SENERK=SENERK+DEXPORT
    GO TO 200

 30 SENERH=SENERH+DEXPORT

    IF SENERH>SENERHC THEN GO TO 50
    GO TO 200

 40 SENERC=SENERC+DEXPORT

    IF SENERC<SENERCC THEN GO TO 200

    SENERC=SENERCC

    SENERK=SENERK+DEXPORT-DIFFC
    GO TO 200

 50 SENERH=SENERHC

    SENERC=SENERC+DEXPORT-DIFFH

    IF SENERC<SENERCC THEN GO TO 200

    SENERC=SENERCC

    SENERK=SENERK+DEXPORT-DIFFH-DIFFC
    GO TO 200

100 DEXPORT=A(1873)*(SENERHC+SENERCC-DGROSS)
```

```
   IF DEXPORT<0. THEN DEXPORT=0.

   IF DEXPORT=0. THEN GO TO 200
   IF A(1862)<A(1879) THEN GO TO 110

   DEXPORT=SENERHC-DGROSS

   IF DEXPORT<0. THEN DEXPORT=0.

   IF DEXPORT=0. THEN GO TO 200

   SENERH=SENERH+DEXPORT
   GO TO 200
110 DIFFH=SENERHC-SENERH
   IF DIFFH>0. THEN GO TO 120

   SENERC=SENERC+DEXPORT
   GO TO 200

120 SENERH=SENERH+DEXPORT

   IF SENERH<SENERHC THEN GO TO 200

   SENERH=SENERHC

   SENERC=SENERC+DEXPORT-DIFFH
   GO TO 200

  SENER - TOTAL ENERGY GENERATED

200 SENER=SENERH+SENERC+SENERK+SENERB+SENERG

   THIS SECTION TAKES INFORMATION FROM POLS1 ON APPROVAL DATES FOR
             MAJOR GENERATION AND TRANSMISSION PROJECTS AND
             CALCULATES ANNUAL CAPITAL INVESTMENT (INCLUDING
             INTEREST DURING CONSTRUCTION) THAT RESULTS. IT
             ALSO CALCULATES ADDITIONS TO PLANT IN SERVICE
             AND THE NEW ENERGY(CRITICAL AND AVERAGE) AND
             CAPACITY CAPABILITIES FOLLOWING THE COMPLETION
             OF THESE NEW PROJECTS.

  INITIALIZE SUBROUTINE-SPECIFIC VARIABLES TO ZERO FOR:

  VARIOUS CATEGORIES (HYDRO,HAT CREEK,EAST KOOTENAY,GAS TURBINE,
             TRANSMISSION) OF POST-74 PLANT IN SERVICE($76)
   PH$76=0.
   PC$76=0.
   PK$76=0.
   PG$76=0.
   PT$76=0.

  VARIOUS CATEGORIES OF POST-74 PLANT IN SERVICE ($H)
   PH$H=0.
   PC$H=0.
   PK$H=0.
   PG$H=0.
```

```
  PT$H=0.
```



```
HYDRO-ELECTRIC ENERGY CAPABILITY DURING CRITICAL RAINFALL PERIODS
  SEHCC=0.

VARIOUS CATEGORIES OF AVERAGE ENERGY CAPABILITY
  SEHAC=0.
  SECAC=0.
  SEKAC=0.
  SEGAC=0.

VARIOUS CATEGORIES OF GENERATION CAPACITY CAPABILITY
  SCH=0.
  SCC=0.
  SCK=0.
  SCG=0.

CAPITAL EXPENDITURES ($76) FOR EACH GENERATION PROJECT
  G1$76=0.
  G2$76=0.
  G3$76=0.
  G4$76=0.
  G5$76=0.
  G6$76=0.
  G7$76=0.
  G8$76=0.
  G9$76=0.
  G10$76=0.
  G11$76=0.
  G12$76=0.
  G13$76=0.
  G14$76=0.
  G15$76=0.
  G16$76=0.
  G17$76=0.
  G18$76=0.
  G19$76=0.
  G20$76=0.
  G21$76=0.
  G22$76=0.
  G23$76=0.
  G24$76=0.
  G25$76=0.
  G26$76=0.
  G27$76=0.
  G28$76=0.
  G29$76=0.
  G30$76=0.
  G31$76=0.
  G32$76=0.
  G33$76=0.
  G34$76=0.
  G35$76=0.
  G36$76=0.
  G37$76=0.
  G38$76=0.
  G39$76=0.
  G40$76=0.
  G41$76=0.
  G42$76=0.
```

```
  G43$76=0.
  G44$76=0.
  G45$76=0.
  G46$76=0.
  G47$76=0.
  G48$76=0.
  G49$76=0.
  G50$76=0.

CAPITAL EXPENDITURES ($76) FOR EACH MAJOR ASSOCIATED TRANSMISSION
             PROJECT
  T1$76=0.
  T2$76=0.
  T3$76=0.
  T4$76=0.
  T6$76=0.
  T8$76=0.
  T9$76=0.
  T10$76=0.
  T21$76=0.
  T31$76=0.
  T36$76=0.
  T38$76=0.
  T40$76=0.
  T44$76=0.
  T45$76=0.

GO TO APPROPRIATE PROJECTS IF COEFFICIENTS INDICATE AN ECONOMIC
             ANALYSIS OF PROJECT IS DESIRED
  IF A(2011)=0. THEN GO TO 5
  IF A(2011)=1. THEN GO TO 90
  IF A(2011)=2. THEN GO TO 120
  IF A(2011)=3. THEN GO TO 130
  IF A(2011)=4. THEN GO TO 140
  IF A(2011)=5. THEN GO TO 160
  IF A(2011)=6. THEN GO TO 80
  IF A(2011)=7. THEN GO TO 210
  IF A(2011)=8. THEN GO TO 60
  IF A(2011)=11. THEN GO TO 310
  IF A(2011)=16. THEN GO TO 360
  IF A(2011)=17. THEN GO TO 400
  IF A(2011)=21. THEN GO TO 440
5 IF A(2010)=0. THEN GO TO 10
  IF A(2010)=6. THEN GO TO 60
  IF A(2010)=7. THEN GO TO 70
  IF A(2010)=8. THEN GO TO 80
  IF A(2010)=9. THEN GO TO 90
  IF A(2010)=10. THEN GO TO 100
  IF A(2010)=11. THEN GO TO 110
  IF A(2010)=12. THEN GO TO 120
  IF A(2010)=13. THEN GO TO 130
  IF A(2010)=14. THEN GO TO 140
  IF A(2010)=16. THEN GO TO 160
  IF A(2010)=17. THEN GO TO 170
  IF A(2010)=18. THEN GO TO 180
  IF A(2010)=19. THEN GO TO 190
  IF A(2010)=20. THEN GO TO 200
  IF A(2010)=21. THEN GO TO 210
  IF A(2010)=22. THEN GO TO 220
  IF A(2010)=23. THEN GO TO 230
```

```
   IF A(2010)=31. THEN GO TO 310
   IF A(2010)=32. THEN GO TO 320
   IF A(2010)=36. THEN GO TO 360
   IF A(2010)=37. THEN GO TO 370
   IF A(2010)=38. THEN GO TO 380
   IF A(2010)=39. THEN GO TO 390
   IF A(2010)=40. THEN GO TO 400
   IF A(2010)=41. THEN GO TO 410
   IF A(2010)=42. THEN GO TO 420
   IF A(2010)=43. THEN GO TO 430
   IF A(2010)=44. THEN GO TO 440
   IF A(2010)=45. THEN GO TO 450

 CALCULATE FINANCIAL AND ENGINEERING INFORMATION FROM KNOWLEDGE
             ABOUT STARTING DATE OF EACH GENERATION PROJECT
             SEE STATEMENT 90 FOR EXPLANATION OF TYPICAL SET OF
             CALCULATIONS IN THIS SECTION
10 IF RTIME>STARG1 THEN GO TO 20
   IF RTIME=STARG1 THEN G1$76=13.1*A(1901)
   IG1$=PEXOG/2.11*G1$76
   IDCG1$=6.
   IDC$=IDC$+IDCG1$
20 IF RTIME>STARG2 THEN GO TO 30
   IF RTIME<STARG2 THEN GO TO 30
   IF RTIME=STARG2 THEN G2$76=4.8*A(1902)
   IG2$=PEXOG/2.11*G2$76
   IDCG2$=2.
   IDC$=IDC$+IDCG2$
   IF RTIME NOT= STARG2 THEN GO TO 30
   PH$76=PH$76+(25.8*A(1902))
   PH$H=PH$H+25.6
   SEHCC=SEHCC+1747.
   SEHAC=SEHAC+1920.
   SCH=SCH+250.
30 IF RTIME>(STARG3+1.) THEN GO TO 40
   IF RTIME=STARG3 THEN G3$76=60.5*A(1903)
   IF RTIME=(STARG3+1.) THEN G3$76=41.5*A(1903)
   IG3$=PEXOG/2.11*G3$76
   IF RTIME=STARG3 THEN IDCG3$=13.
   IF RTIME=(STARG3+1.) THEN IDCG3$=18.
   IDC$=IDC$+IDCG3$
   IF RTIME NOT= (STARG3+1.) THEN GO TO 40
   PH$76=PH$76+(199.6*A(1903))
   PH$H=PH$H+255.
   SEHCC=SEHCC+2386.
   SEHAC=SEHAC+2760.
   SCH=SCH+800.
40 IF RTIME>STARG4 THEN GO TO 50
   IF RTIME=STARG4 THEN G4$76=13.6*A(1904)
   IG4$=PEXOG/2.11*G4$76
   IF RTIME=(STARG4-1.) THEN IDCG4$=3.
   IF RTIME=STARG4 THEN IDCG4$=6.5
   IF RTIME=(STARG4+1.) THEN IDCG4$=14.
   IDC$=IDC$+IDCG4$
   IF RTIME NOT= STARG4 THEN GO TO 50
   PH$76=PH$76+(66.7*A(1904))
   PH$H=PH$H+103.
   SEHCC=SEHCC+3654.
   SEHAC=SEHAC+4225.
   SCH=SCH+800.
```

```
50 IF RTIME>STARG5 THEN GO TO 60
   IF RTIME=STARG5 THEN G5$76=.2*A(1905)
   IG5$=PEXOG/2.11*G5$76
   IF RTIME=(STARG5-3.) THEN IDCG5$=1.
   IF RTIME=(STARG5-2.) THEN IDCG5$=3.
   IF RTIME=(STARG5-1.) THEN IDCG5$=6.
   IF RTIME=STARG5 THEN IDCG5$=12.
   IDC$=IDC$+IDCG5$
   IF RTIME NOT= STARG5 THEN GO TO 60
   PH$76=PH$76+(100.*A(1905))
   PH$H=PH$H+179.
   SEHCC=SEHCC+700.
   SEHAC=SEHAC+810.
   SCH=SCH+0.
60 IF RTIME>(STARG6+4.) THEN GO TO 68
   IF RTIME=STARG6 THEN G6$76=21.6*A(1906)
   IF RTIME=(STARG6+1.) THEN G6$76=46.9*A(1906)
   IF RTIME=(STARG6+2.) THEN G6$76=53.4*A(1906)
   IF RTIME=(STARG6+3.) THEN G6$76=42.4*A(1906)
   IF RTIME=(STARG6+4.) THEN G6$76=20.9*A(1906)
   IG6$=PEXOG/2.11*G6$76
   IDCG6$=A(1872)*((.5*IG6$)+J1L*IG6$+J2L*IG6$+
          J3L*IG6$+J4L*IG6$+J5L*IG6$+J6L*IG6$)
   IDC$=IDC$+IDCG6$
   IF RTIME NOT= (STARG6+4.) THEN GO TO 68
   PH$76=PH$76+(185.2*A(1906))
   PH$H=PH$H+IG6$+J1L*IG6$+J2L*IG6$+J3L*IG6$+
          J4L*IG6$+J5L*IG6$+J6L*IG6$+IDCG6$+J1L*IDCG6$+
          J2L*IDCG6$+J3L*IDCG6$+J4L*IDCG6$+J5L*IDCG6$+J6L*IDCG6$
   SEHCC=SEHCC+1941.
   SEHAC=SEHAC+1881.
   SCH=SCH+525.
68 IF A(2011) NOT= 0. THEN GO TO 70
   IF A(2010) NOT= 0. THEN GO TO 505
70 IF RTIME>(STARG7+4.) THEN GO TO 78
   IF RTIME=STARG7 THEN G7$76=1.*A(1907)
   IF RTIME=(STARG7+1.) THEN G7$76=1.6*A(1907)
   IF RTIME=(STARG7+2.) THEN G7$76=2.9*A(1907)
   IF RTIME=(STARG7+3.) THEN G7$76=4.3*A(1907)
   IF RTIME=(STARG7+4.) THEN G7$76=5.9*A(1907)
   IG7$=PEXOG/2.11*G7$76
   IDCG7$=A(1872)*((.5*IG7$)+J1L*IG7$+J2L*IG7$+
          J3L*IG7$+J4L*IG7$+J5L*IG7$+J6L*IG7$)
   IDC$=IDC$+IDCG7$
   IF RTIME NOT= (STARG7+4.) THEN GO TO 78
   PH$76=PH$76+(15.7*A(1907))
   PH$H=PH$H+IG7$+J1L*IG7$+J2L*IG7$+J3L*IG7$+
          J4L*IG7$+J5L*IG7$+J6L*IG7$+IDCG7$+J1L*IDCG7$+
          J2L*IDCG7$+J3L*IDCG7$+J4L*IDCG7$+J5L*IDCG7$+J6L*IDCG7$
   SEHCC=SEHCC+1412.
   SEHAC=SEHAC+1369.
   SCH=SCH+175.
78 IF A(2011) NOT= 0. THEN GO TO 505
   IF A(2010) NOT= 0. THEN GO TO 505
80 IF RTIME>(STARG8+5.) THEN GO TO 88
   IF RTIME=STARG8 THEN G8$76=9.7*A(1908)
   IF RTIME=(STARG8+1.) THEN G8$76=17.4*A(1908)
   IF RTIME=(STARG8+2.) THEN G8$76=37.5*A(1908)
   IF RTIME=(STARG8+3.) THEN G8$76=51.9*A(1908)
   IF RTIME=(STARG8+4.) THEN G8$76=41.6*A(1908)
```

```
  IF RTIME=(STARG8+5.) THEN G8$76=7.5*A(1908)
  IG8$=PEXOG/2.11*G8$76
  IDCG8$=A(1872)*((.5*IG8$)+J1L*IG8$+J2L*IG8$+
          J3L*IG8$+J4L*IG8$+J5L*IG8$+J6L*IG8$)
  IDC$=IDC$+IDCG8$
  IF RTIME NOT= (STARG8+5.) THEN GO TO 88
  PH$76=PH$76+(165.6*A(1908))
  PH$H=PH$H+IG8$+J1L*IG8$+J2L*IG8$+J3L*IG8$+
          J4L*IG8$+J5L*IG8$+J6L*IG8$+IDCG8$+J1L*IDCG8$+
          J2L*IDCG8$+J3L*IDCG8$+J4L*IDCG8$+J5L*IDCG8$+J6L*IDCG8$
  SEHCC=SEHCC+2610.
  SEHAC=SEHAC+3004.
  SCH=SCH+525.

 SEE IF THIS PROJECT IS BEING COSTED
88 IF A(2011) NOT= 0. THEN GO TO 200

 SEE IF THIS UNIT IS BEING COSTED
  IF A(2010) NOT= 0. THEN GO TO 505

 SEE IF THIS PROJECT HAS ALREADY BEEN COMPLETED
90 IF RTIME>(STARG9+6.) THEN GO TO 98

 DETERMINE REAL CONSTRUCTION EXPENDITURES IN THE CURRENT YEAR
  IF RTIME=STARG9 THEN G9$76=5.1*A(1909)
  IF RTIME=(STARG9+1.) THEN G9$76=32.7*A(1909)
  IF RTIME=(STARG9+2.) THEN G9$76=37.9*A(1909)
  IF RTIME=(STARG9+3.) THEN G9$76=73.6*A(1909)
  IF RTIME=(STARG9+4.) THEN G9$76=132.1*A(1909)
  IF RTIME=(STARG9+5.) THEN G9$76=152.3*A(1909)
  IF RTIME=(STARG9+6.) THEN G9$76=23.*A(1909)

 DETERMINE NOMINAL CONSTRUCTION EXPENDITURES IN THE CURRENT YEAR
  IG9$=PEXOG/2.11*G9$76

 CALCULATE INTEREST DURING CONSTRUCTION FOR THIS PROJECT
  IDCG9$=A(1872)*((.5*IG9$)+J1L*IG9$+J2L*IG9$+
          J3L*IG9$+J4L*IG9$+J5L*IG9$+J6L*IG9$)

 CALCULATE ALL INTEREST DURING CONSTRUCTION FOR THE CURRENT YEAR
  IDC$=IDC$+IDCG9$
  IF RTIME NOT= (STARG9+6.) THEN GO TO 98

 HERE IF PROJECT IS COMPLETED THIS YEAR

 AUGMENT REAL PLANT IN SERVICE FOR THIS CATEGORY (HYDRO)
  PH$76=PH$76+(456.7*A(1909))

 AUGMENT HISTORIC DOLLAR PLANT IN SERVICE FOR THIS CATEGORY (HYDRO)
  PH$H=PH$H+IG9$+J1L*IG9$+J2L*IG9$+J3L*IG9$+
          J4L*IG9$+J5L*IG9$+J6L*IG9$+IDCG9$+J1L*IDCG9$+
          J2L*IDCG9$+J3L*IDCG9$+J4L*IDCG9$+J5L*IDCG9$+J6L*IDCG9$

 AUGMENT CRITICAL ENERGY CAPABILITY FOR THIS CATEGORY (HYDRO)
  SEHCC=SEHCC+4773.

 AUGMENT AVERAGE ENERGY CAPABILITY FOR THIS CATEGORY (HYDRO)
  SEHAC=SEHAC+5520.

 AUGMENT CAPACITY CAPABILITY FOR THIS CATEGORY (HYDRO)
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    SCH=SCH+900.
 98 IF A(2011) NOT= 0. THEN GO TO 100
    IF A(2010) NOT= 0. THEN GO TO 505
100 IF RTIME>(STARG10+6.) THEN GO TO 108
    IF RTIME=STARG10 THEN G10$76=.1*A(1910)
    IF RTIME=(STARG10+1.) THEN G10$76=1.9*A(1910)
    IF RTIME=(STARG10+2.) THEN G10$76=2.9*A(1910)
    IF RTIME=(STARG10+3.) THEN G10$76=4.8*A(1910)
    IF RTIME=(STARG10+4.) THEN G10$76=7.9*A(1910)
    IF RTIME=(STARG10+5.) THEN G10$76=4.5*A(1910)
    IF RTIME=(STARG10+6.) THEN G10$76=0.*A(1910)
    IG10$=PEXOG/2.11*G10$76
    IDCG10$=A(1872)*((.5*IG10$)+J1L*IG10$+J2L*IG10$+
            J3L*IG10$+J4L*IG10$+J5L*IG10$+J6L*IG10$)
    IDC$=IDC$+IDCG10$
    IF RTIME NOT= (STARG10+5.) THEN GO TO 108
    PH$76=PH$76+(22.1*A(1910))
    PH$H=PH$H+IG10$+J1L*IG10$+J2L*IG10$+J3L*IG10$+
            J4L*IG10$+J5L*IG10$+J6L*IG10$+IDCG10$+J1L*IDCG10$+
            J2L*IDCG10$+J3L*IDCG10$+J4L*IDCG10$+J5L*IDCG10$+J6L*IDCG10$
    SEHCC=SEHCC+1634.
    SEHAC=SEHAC+1890.
    SCH=SCH+450.
108 IF A(2011) NOT= 0. THEN GO TO 110
    IF A(2010) NOT= 0. THEN GO TO 505
110 IF RTIME>(STARG11+4.) THEN GO TO 118
    IF RTIME=STARG11 THEN G11$76=1.9*A(1911)
    IF RTIME=(STARG11+1.) THEN G11$76=2.9*A(1911)
    IF RTIME=(STARG11+2.) THEN G11$76=4.8*A(1911)
    IF RTIME=(STARG11+3.) THEN G11$76=7.9*A(1911)
    IF RTIME=(STARG11+4.) THEN G11$76=4.5*A(1911)
    IG11$=PEXOG/2.11*G11$76
    IDCG11$=A(1872)*((.5*IG11$)+J1L*IG11$+J2L*IG11$+
            J3L*IG11$+J4L*IG11$+J5L*IG11$+J6L*IG11$)
    IDC$=IDC$+IDCG11$
    IF RTIME NOT= (STARG11+4.) THEN GO TO 118
    PH$76=PH$76+(22.*A(1911))
    PH$H=PH$H+IG11$+J1L*IG11$+J2L*IG11$+J3L*IG11$+
            J4L*IG11$+J5L*IG11$+J6L*IG11$+IDCG11$+J1L*IDCG11$+
            J2L*IDCG11$+J3L*IDCG11$+J4L*IDCG11$+J5L*IDCG11$+J6L*IDCG11$
    SEHCC=SEHCC+484.
    SEHAC=SEHAC+560.
    SCH=SCH+450.
118 IF A(2011) NOT= 0. THEN GO TO 180
    IF A(2010) NOT= 0. THEN GO TO 505
120 IF RTIME<STARG12 THEN GO TO 128
    IF RTIME>(STARG12+2.) THEN GO TO 128
    IF RTIME=STARG12 THEN G12$76=2.*A(1912)
    IF RTIME=(STARG12+1.) THEN G12$76=5.*A(1912)
    IF RTIME=(STARG12+2.) THEN G12$76=3.1*A(1912)
    IG12$=PEXOG/2.11*G12$76
    IDCG12$=A(1872)*((.5*IG12$)+J1L*IG12$+J2L*IG12$+
            J3L*IG12$+J4L*IG12$+J5L*IG12$+J6L*IG12$)
    IDC$=IDC$+IDCG12$
    IF RTIME NOT= (STARG12+2.) THEN GO TO 128
    PH$76=PH$76+(10.1*A(1912))
    PH$H=PH$H+IG12$+J1L*IG12$+J2L*IG12$+J3L*IG12$+
            J4L*IG12$+J5L*IG12$+J6L*IG12$+IDCG12$+J1L*IDCG12$+
            J2L*IDCG12$+J3L*IDCG12$+J4L*IDCG12$+J5L*IDCG12$+J6L*IDCG12$
    SEHCC=SEHCC+875.
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    SEHAC=SEHAC+875.
    SCH=SCH+0.
128 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
130 IF RTIME<STARG13 THEN GO  TO 138
    IF RTIME>(STARG13+3.) THEN GO  TO 138
    IF RTIME=STARG13 THEN G13$76=2.4*A(1913)
    IF RTIME=(STARG13+1.) THEN G13$76=5.3*A(1913)
    IF RTIME=(STARG13+2.) THEN G13$76=6.*A(1913)
    IF RTIME=(STARG13+3.) THEN G13$76=2.5*A(1913)
    IG13$=PEXOG/2.11*G13$76
    IDCG13$=A(1872)*((.5*IG13$)+J1L*IG13$+J2L*IG13$+
             J3L*IG13$+J4L*IG13$+J5L*IG13$+J6L*IG13$)
    IDC$=IDC$+IDCG13$
    IF RTIME NOT= (STARG13+3.) THEN GO  TO 138
    PH$76=PH$76+(16.2*A(1913))
    PH$H=PH$H+IG13$+J1L*IG13$+J2L*IG13$+J3L*IG13$+
             J4L*IG13$+J5L*IG13$+J6L*IG13$+IDCG13$+J1L*IDCG13$+
             J2L*IDCG13$+J3L*IDCG13$+J4L*IDCG13$+J5L*IDCG13$+J6L*IDCG13$
    SEHCC=SEHCC+0.
    SEHAC=SEHAC+0.
    SCH=SCH+275.
138 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
140 IF RTIME<STARG14 THEN GO TO 158
    IF RTIME>(STARG14+6.) THEN GO TO 158
    IF RTIME=STARG14 THEN G14$76=1.9*A(1914)
    IF RTIME=(STARG14+1.) THEN G14$76=12.8*A(1914)
    IF RTIME=(STARG14+2.) THEN G14$76=33.8*A(1914)
    IF RTIME=(STARG14+3.) THEN G14$76=42.5*A(1914)
    IF RTIME=(STARG14+4.) THEN G14$76=28.4*A(1914)
    IF RTIME=(STARG14+5.) THEN G14$76=11.9*A(1914)
    IF RTIME=(STARG14+6.) THEN G14$76=2.1*A(1914)
    IG14$=PEXOG/2.11*G14$76
    IDCG14$=A(1872)*((.5*IG14$)+J1L*IG14$+J2L*IG14$+
             J3L*IG14$+J4L*IG14$+J5L*IG14$+J6L*IG14$)
    IDC$=IDC$+IDCG14$
    IF RTIME NOT= (STARG14+6.) THEN GO TO 158
    PH$76=PH$76+(133.4*A(1914))
    PH$H=PH$H+IG14$+J1L*IG14$+J2L*IG14$+J3L*IG14$+
             J4L*IG14$+J5L*IG14$+J6L*IG14$+IDCG14$+J1L*IDCG14$+
             J2L*IDCG14$+J3L*IDCG14$+J4L*IDCG14$+J5L*IDCG14$+J6L*IDCG14$
    IF STARG21<=STARG14 THEN GO TO 150
    SEHCC=SEHCC+2750.
    SEHAC=SEHAC+3110.
    SCH=SCH+0.
    GO TO 158
150 SEHCC=SEHCC+3346.
    SEHAC=SEHAC+3828.
    SCH=SCH+0.
158 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
160 IF RTIME<STARG16 THEN GO TO 168
    IF RTIME>(STARG16+4.) THEN GO TO 168
    IF RTIME=STARG16 THEN G16$76=1.*A(1916)
    IF RTIME=(STARG16+1.) THEN G16$76=2.*A(1916)
    IF RTIME=(STARG16+2.) THEN G16$76=3.*A(1916)
    IF RTIME=(STARG16+3.) THEN G16$76=7.*A(1916)
    IF RTIME=(STARG16+4.) THEN G16$76=3.*A(1916)
    IG16$=PEXOG/2.11*G16$76
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    IDCG16$=A(1872)*((.5*IG16$)+J1L*IG16$+J2L*IG16$+
            J3L*IG16$+J4L*IG16$+J5L*IG16$+J6L*IG16$)
    IDC$=IDC$+IDCG16$
    IF RTIME NOT= (STARG16+4.) THEN GO TO 168
    PH$76=PH$76+(16.*A(1916))
    PH$H=PH$H+IG16$+J1L*IG16$+J2L*IG16$+J3L*IG16$+
            J4L*IG16$+J5L*IG16$+J6L*IG16$+IDCG16$+J1L*IDCG16$+
            J2L*IDCG16$+J3L*IDCG16$+J4L*IDCG16$+J5L*IDCG16$+J6L*IDCG16$
    SEHCC=SEHCC+0.
    SEHAC=SEHAC+0.
    SCH=SCH+400.
168 IF A(2011) NOT= 0. THEN GO TO 170
    IF A(2010) NOT= 0. THEN GO TO 505
170 IF RTIME<STARG17 THEN GO TO 178
    IF RTIME>(STARG17+4.) THEN GO TO 178
    IF RTIME=STARG17 THEN G17$76=1.*A(1917)
    IF RTIME=(STARG17+1.) THEN G17$76=2.*A(1917)
    IF RTIME=(STARG17+2.) THEN G17$76=3.*A(1917)
    IF RTIME=(STARG17+3.) THEN G17$76=6.3*A(1917)
    IF RTIME=(STARG17+4.) THEN G17$76=3.*A(1917)
    IG17$=PEXOG/2.11*G17$76
    IDCG17$=A(1872)*((.5*IG17$)+J1L*IG17$+J2L*IG17$+
            J3L*IG17$+J4L*IG17$+J5L*IG17$+J6L*IG17$)
    IDC$=IDC$+IDCG17$
    IF RTIME NOT= (STARG17+4.) THEN GO TO 178
    PH$76=PH$76+(15.3*A(1917))
    PH$H=PH$H+IG17$+J1L*IG17$+J2L*IG17$+J3L*IG17$+
            J4L*IG17$+J5L*IG17$+J6L*IG17$+IDCG17$+J1L*IDCG17$+
            J2L*IDCG17$+J3L*IDCG17$+J4L*IDCG17$+J5L*IDCG17$+J6L*IDCG17$
    SEHCC=SEHCC+0.
    SEHAC=SEHAC+0.
    SCH=SCH+400.
178 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
180 IF RTIME<STARG18 THEN GO TO 188
    IF RTIME>(STARG18+4.) THEN GO TO 188
    IF RTIME=STARG18 THEN G18$76=2.*A(1918)
    IF RTIME=(STARG18+1.) THEN G18$76=3.*A(1918)
    IF RTIME=(STARG18+2.) THEN G18$76=5.*A(1918)
    IF RTIME=(STARG18+3.) THEN G18$76=8.*A(1918)
    IF RTIME=(STARG18+4.) THEN G18$76=6.9*A(1918)
    IG18$=PEXOG/2.11*G18$76
    IDCG18$=A(1872)*((.5*IG18$)+J1L*IG18$+J2L*IG18$+
            J3L*IG18$+J4L*IG18$+J5L*IG18$+J6L*IG18$)
    IDC$=IDC$+IDCG18$
    IF RTIME NOT= (STARG18+4.) THEN GO TO 188
    PH$76=PH$76+(24.9*A(1918))
    PH$H=PH$H+IG18$+J1L*IG18$+J2L*IG18$+J3L*IG18$+
            J4L*IG18$+J5L*IG18$+J6L*IG18$+IDCG18$+J1L*IDCG18$+
            J2L*IDCG18$+J3L*IDCG18$+J4L*IDCG18$+J5L*IDCG18$+J6L*IDCG18$
    SEHCC=SEHCC+0.
    SEHAC=SEHAC+0.
    SCH=SCH+450.
188 IF A(2011) NOT= 0. THEN GO TO 190
    IF A(2010) NOT= 0. THEN GO TO 505
190 IF RTIME<STARG19 THEN GO TO 198
    IF RTIME>(STARG19+4.) THEN GO TO 198
    IF RTIME=STARG19 THEN G19$76=2.*A(1919)
    IF RTIME=(STARG19+1.) THEN G19$76=3.*A(1919)
    IF RTIME=(STARG19+2.) THEN G19$76=5.*A(1919)
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    IF RTIME=(STARG19+3.) THEN G19$76=8.*A(1919)
    IF RTIME=(STARG19+4.) THEN G19$76=4.7*A(1919)
    IG19$=PEXOG/2.11*G19$76
    IDCG19$=A(1872)*((.5*IG19$)+J1L*IG19$+J2L*IG19$+
            J3L*IG19$+J4L*IG19$+J5L*IG19$+J6L*IG19$)
    IDC$=IDC$+IDCG19$
    IF RTIME NOT= (STARG19+4.) THEN GO TO 198
    PH$76=PH$76+(22.7*A(1919))
    PH$H=PH$H+IG19$+J1L*IG19$+J2L*IG19$+J3L*IG19$+
            J4L*IG19$+J5L*IG19$+J6L*IG19$+IDCG19$+J1L*IDCG19$+
            J2L*IDCG19$+J3L*IDCG19$+J4L*IDCG19$+J5L*IDCG19$+J6L*IDCG19$
    SEHCC=SEHCC+0.
    SEHAC=SEHAC+0.
    SCH=SCH+450.
198 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
200 IF RTIME<STARG20 THEN GO TO 208
    IF RTIME>(STARG20+4.) THEN GO TO 208
    IF RTIME=STARG20 THEN G20$76=.7*A(1920)
    IF RTIME=(STARG20+1.) THEN G20$76=1.1*A(1920)
    IF RTIME=(STARG20+2.) THEN G20$76=1.7*A(1920)
    IF RTIME=(STARG20+3.) THEN G20$76=5.4*A(1920)
    IF RTIME=(STARG20+4.) THEN G20$76=5.7*A(1920)
    IG20$=PEXOG/2.11*G20$76
    IDCG20$=A(1872)*((.5*IG20$)+J1L*IG20$+J2L*IG20$+
            J3L*IG20$+J4L*IG20$+J5L*IG20$+J6L*IG20$)
    IDC$=IDC$+IDCG20$
    IF RTIME NOT= (STARG20+4.) THEN GO TO 208
    PH$76=PH$76+(14.6*A(1920))
    PH$H=PH$H+IG20$+J1L*IG20$+J2L*IG20$+J3L*IG20$+
            J4L*IG20$+J5L*IG20$+J6L*IG20$+IDCG20$+J1L*IDCG20$+
            J2L*IDCG20$+J3L*IDCG20$+J4L*IDCG20$+J5L*IDCG20$+J6L*IDCG20$
    SEHCC=SEHCC+65.
    SEHAC=SEHAC+75.
    SCH=SCH+175.
208 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
210 IF STARG21=0. THEN GO TO 238
    IF RTIME>(STARG21+6.) THEN GO TO 218
    IF RTIME=STARG21 THEN G21$76=3.*A(1921)
    IF RTIME=(STARG21+1.) THEN G21$76=24.*A(1921)
    IF RTIME=(STARG21+2.) THEN G21$76=28.5*A(1921)
    IF RTIME=(STARG21+3.) THEN G21$76=54.*A(1921)
    IF RTIME=(STARG21+4.) THEN G21$76=98.*A(1921)
    IF RTIME=(STARG21+5.) THEN G21$76=111.*A(1921)
    IF RTIME=(STARG21+6.) THEN G21$76=17.*A(1921)
    IG21$=PEXOG/2.11*G21$76
    IDCG21$=A(1872)*((.5*IG21$)+J1L*IG21$+J2L*IG21$+
            J3L*IG21$+J4L*IG21$+J5L*IG21$+J6L*IG21$)
    IDC$=IDC$+IDCG21$
    IF RTIME NOT= (STARG21+6.) THEN GO TO 218
    PH$76=PH$76+(335.5*A(1921))
    PH$H=PH$H+IG21$+J1L*IG21$+J2L*IG21$+J3L*IG21$+
            J4L*IG21$+J5L*IG21$+J6L*IG21$+IDCG21$+J1L*IDCG21$+
            J2L*IDCG21$+J3L*IDCG21$+J4L*IDCG21$+J5L*IDCG21$+J6L*IDCG21$
    SEHCC=SEHCC+2702.
    SEHAC=SEHAC+2600.
    SCH=SCH+450.
218 IF A(2011) NOT= 0. THEN GO TO 220
    IF A(2010) NOT= 0. THEN GO TO 505
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220 IF RTIME>(STARG22+4.) THEN GO TO 228
    IF RTIME=STARG22 THEN G22$76=1.*A(1922)
    IF RTIME=(STARG22+1.) THEN G22$76=1.6*A(1922)
    IF RTIME=(STARG22+2.) THEN G22$76=2.9*A(1922)
    IF RTIME=(STARG22+3.) THEN G22$76=4.3*A(1922)
    IF RTIME=(STARG22+4.) THEN G22$76=5.2*A(1922)
    IG22$=PEXOG/2.11*G22$76
    IDCG22$=A(1872)*((.5*IG22$)+J1L*IG22$+J2L*IG22$+
            J3L*IG22$+J4L*IG22$+J5L*IG22$+J6L*IG22$)
    IDC$=IDC$+IDCG22$
    IF RTIME NOT= (STARG22+4.) THEN GO TO 228
    PH$76=PH$76+(15.*A(1922))
    PH$H=PH$H+IG22$+J1L*IG22$+J2L*IG22$+J3L*IG22$+
            J4L*IG22$+J5L*IG22$+J6L*IG22$+IDCG22$+J1L*IDCG22$+
            J2L*IDCG22$+J3L*IDCG22$+J4L*IDCG22$+J5L*IDCG22$+J6L*IDCG22$
    SEHCC=SEHCC+1143.
    SEHAC=SEHAC+1100.
    SCH=SCH+225.
228 IF A(2011) NOT= 0. THEN GO TO 230
    IF A(2010) NOT= 0. THEN GO TO 505
230 IF RTIME>(STARG23+4.) THEN GO TO 238
    IF RTIME=STARG23 THEN G23$76=1.*A(1923)
    IF RTIME=(STARG23+1.) THEN G23$76=1.6*A(1923)
    IF RTIME=(STARG23+2.) THEN G23$76=2.9*A(1923)
    IF RTIME=(STARG23+3.) THEN G23$76=4.3*A(1923)
    IF RTIME=(STARG23+4.) THEN G23$76=5.2*A(1923)
    IG23$=PEXOG/2.11*G23$76
    IDCG23$=A(1872)*((.5*IG23$)+J1L*IG23$+J2L*IG23$+
            J3L*IG23$+J4L*IG23$+J5L*IG23$+J6L*IG23$)
    IDC$=IDC$+IDCG23$
    IF RTIME NOT= (STARG23+4.) THEN GO TO 238
    PH$76=PH$76+(15.*A(1923))
    PH$H=PH$H+IG23$+J1L*IG23$+J2L*IG23$+J3L*IG23$+
            J4L*IG23$+J5L*IG23$+J6L*IG23$+IDCG23$+J1L*IDCG23$+
            J2L*IDCG23$+J3L*IDCG23$+J4L*IDCG23$+J5L*IDCG23$+J6L*IDCG23$
    SEHCC=SEHCC+613.
    SEHAC=SEHAC+590.
    SCH=SCH+225.
238 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
240 IF STARG24=0. THEN GO TO 310
310 IF RTIME<STARG31 THEN GO TO 318
    IF RTIME>(STARG31+1.) THEN GO TO 318
    IF RTIME=STARG31 THEN G31$76=11.6*A(1931)
    IF RTIME=(STARG31+1.) THEN G31$76=10.*A(1931)
    IG31$=PEXOG/2.11*G31$76
    IDCG31$=A(1872)*((.5*IG31$)+J1L*IG31$)
    IDC$=IDC$+IDCG31$
    IF RTIME NOT= (STARG31+1.) THEN GO TO 318
    PG$76=PG$76+(21.6*A(1931))
    PG$H=PG$H+IG31$+J1L*IG31$+IDCG31$+J1L*IDCG31$
    SEGAC=SEGAC+657.
    SCG=SCG+150.
318 IF A(2011) NOT= 0. THEN GO TO 320
    IF A(2010) NOT= 0. THEN GO TO 505
320 IF RTIME<STARG32 THEN GO TO 328
    IF RTIME>(STARG32+1.) THEN GO TO 328
    IF RTIME=STARG32 THEN G32$76=11.6*A(1932)
    IF RTIME=(STARG32+1.) THEN G32$76=10.*A(1932)
    IG32$=PEXOG/2.11*G32$76
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    IDCG32$=A(1872)*((.5*IG32$)+J1L*IG32$)
    IDC$=IDC$+IDCG32$
    IF RTIME NOT= (STARG32+1.) THEN GO TO 328
    PG$76=PG$76+(21.6*A(1932))
    PG$H=PG$H+IG32$+J1L*IG32$+IDCG32$+J1L*IDCG32$
    SEGAC=SEGAC+657.
    SCG=SCG+150.
328 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
330 IF RTIME<STARG33 THEN GO TO 338
    IF RTIME>(STARG33+1.) THEN GO TO 338
    IF RTIME=STARG33 THEN G33$76=11.6*A(1933)
    IF RTIME=(STARG33+1.) THEN G33$76=10.*A(1933)
    IG33$=PEXOG/2.11*G33$76
    IDCG33$=A(1872)*((.5*IG33$)+J1L*IG33$)
    IDC$=IDC$+IDCG33$
    IF RTIME NOT= (STARG33+1.) THEN GO TO 338
    PG$76=PG$76+(21.6*A(1933))
    PG$H=PG$H+IG33$+J1L*IG33$+IDCG33$+J1L*IDCG33$
    SEGAC=SEGAC+657.
    SCG=SCG+150.
338 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
340 IF RTIME<STARG34 THEN GO TO 348
    IF RTIME>(STARG34+1.) THEN GO TO 348
    IF RTIME=STARG34 THEN G34$76=23.2*A(1934)
    IF RTIME=(STARG34+1.) THEN G34$76=20.*A(1934)
    IG34$=PEXOG/2.11*G34$76
    IDCG34$=A(1872)*((.5*IG34$)+J1L*IG34$)
    IDC$=IDC$+IDCG34$
    IF RTIME NOT= (STARG34+1.) THEN GO TO 348
    PG$76=PG$76+(43.2*A(1934))
    PG$H=PG$H+IG34$+J1L*IG34$+IDCG34$+J1L*IDCG34$
    SEGAC=SEGAC+1314.
    SCG=SCG+300.
348 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
350 IF RTIME<STARG35 THEN GO TO 358
    IF RTIME>(STARG35+1.) THEN GO TO 358
    IF RTIME=STARG35 THEN G35$76=46.4*A(1935)
    IF RTIME=(STARG35+1.) THEN G35$76=40.*A(1935)
    IG35$=PEXOG/2.11*G35$76
    IDCG35$=A(1872)*((.5*IG35$)+J1L*IG35$)
    IDC$=IDC$+IDCG35$
    IF RTIME NOT= (STARG35+1.) THEN GO TO 358
    PG$76=PG$76+(86.4*A(1935))
    PG$H=PG$H+IG35$+J1L*IG35$+IDCG35$+J1L*IDCG35$
    SEGAC=SEGAC+2628.
    SCG=SCG+600.
358 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
360 IF RTIME>(STARG36+6.) THEN GO TO 368
    IF RTIME<STARG36 THEN GO TO 505
    IF RTIME=STARG36 THEN G36$76=1.*A(1936)
    IF RTIME=(STARG36+1.) THEN G36$76=5.*A(1936)
    IF RTIME=(STARG36+2.) THEN G36$76=20.*A(1936)
    IF RTIME=(STARG36+3.) THEN G36$76=40.*A(1936)
    IF RTIME=(STARG36+4.) THEN G36$76=50.*A(1936)
    IF RTIME=(STARG36+5.) THEN G36$76=59.*A(1936)
    IF RTIME=(STARG36+6.) THEN G36$76=25.*A(1936)
```

```
    IG36$=PEXOG/2.11*G36$76
    IDCG36$=A(1872)*((.5*IG36$)+J1L*IG36$+J2L*IG36$+
           J3L*IG36$+J4L*IG36$+J5L*IG36$+J6L*IG36$)
    IDC$=IDC$+IDCG36$
    IF RTIME NOT= (STARG36+6.) THEN GO TO 368
    PC$76=PC$76+(200.*A(1936))
    PC$H=PC$H+IG36$+J1L*IG36$+J2L*IG36$+J3L*IG36$+
           J4L*IG36$+J5L*IG36$+J6L*IG36$+IDCG36$+J1L*IDCG36$+
           J2L*IDCG36$+J3L*IDCG36$+J4L*IDCG36$+J5L*IDCG36$+J6L*IDCG36$
    SECAC=SECAC+3420.
    SCC=SCC+500.
368 IF A(2011) NOT= 0. THEN GO TO 370
    IF A(2010) NOT= 0. THEN GO TO 505
370 IF RTIME>(STARG37+5.) THEN GO TO 378
    IF RTIME=STARG37 THEN G37$76=2.*A(1937)
    IF RTIME=(STARG37+1.) THEN G37$76=13.*A(1937)
    IF RTIME=(STARG37+2.) THEN G37$76=25.*A(1937)
    IF RTIME=(STARG37+3.) THEN G37$76=25.*A(1937)
    IF RTIME=(STARG37+4.) THEN G37$76=30.*A(1937)
    IF RTIME=(STARG37+5.) THEN G37$76=11.*A(1937)
    IG37$=PEXOG/2.11*G37$76
    IDCG37$=A(1872)*((.5*IG37$)+J1L*IG37$+J2L*IG37$+
           J3L*IG37$+J4L*IG37$+J5L*IG37$+J6L*IG37$)
    IDC$=IDC$+IDCG37$
    IF RTIME NOT= (STARG37+5.) THEN GO TO 378
    PC$76=PC$76+(106.*A(1937))
    PC$H=PC$H+IG37$+J1L*IG37$+J2L*IG37$+J3L*IG37$+
           J4L*IG37$+J5L*IG37$+J6L*IG37$+IDCG37$+J1L*IDCG37$+
           J2L*IDCG37$+J3L*IDCG37$+J4L*IDCG37$+J5L*IDCG37$+J6L*IDCG37$
    SECAC=SECAC+3420.
    SCC=SCC+500.
378 IF A(2011) NOT= 0. THEN GO TO 380
    IF A(2010) NOT= 0. THEN GO TO 505
380 IF RTIME>(STARG38+5.) THEN GO TO 388
    IF RTIME=STARG38 THEN G38$76=2.*A(1938)
    IF RTIME=(STARG38+1.) THEN G38$76=13.*A(1938)
    IF RTIME=(STARG38+2.) THEN G38$76=25.*A(1938)
    IF RTIME=(STARG38+3.) THEN G38$76=25.*A(1938)
    IF RTIME=(STARG38+4.) THEN G38$76=30.*A(1938)
    IF RTIME=(STARG38+5.) THEN G38$76=11.*A(1938)
    IG38$=PEXOG/2.11*G38$76
    IDCG38$=A(1872)*((.5*IG38$)+J1L*IG38$+J2L*IG38$+
           J3L*IG38$+J4L*IG38$+J5L*IG38$+J6L*IG38$)
    IDC$=IDC$+IDCG38$
    IF RTIME NOT= (STARG38+5.) THEN GO TO 388
    PC$76=PC$76+(106.*A(1938))
    PC$H=PC$H+IG38$+J1L*IG38$+J2L*IG38$+J3L*IG38$+
           J4L*IG38$+J5L*IG38$+J6L*IG38$+IDCG38$+J1L*IDCG38$+
           J2L*IDCG38$+J3L*IDCG38$+J4L*IDCG38$+J5L*IDCG38$+J6L*IDCG38$
    SECAC=SECAC+3420.
    SCC=SCC+500.
388 IF A(2011) NOT= 0. THEN GO TO 390
    IF A(2010) NOT= 0. THEN GO TO 505
390 IF RTIME>(STARG39+5.) THEN GO TO 398
    IF RTIME=STARG39 THEN G39$76=2.*A(1939)
    IF RTIME=(STARG39+1.) THEN G39$76=13.*A(1939)
    IF RTIME=(STARG39+2.) THEN G39$76=25.*A(1939)
    IF RTIME=(STARG39+3.) THEN G39$76=25.*A(1939)
    IF RTIME=(STARG39+4.) THEN G39$76=30.*A(1939)
    IF RTIME=(STARG39+5.) THEN G39$76=11.*A(1939)
```

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    IG39$=PEXOG/2.11*G39$76
    IDCG39$=A(1872)*((.5*IG39$)+J1L*IG39$+J2L*IG39$+
            J3L*IG39$+J4L*IG39$+J5L*IG39$+J6L*IG39$)
    IDC$=IDC$+IDCG39$
    IF RTIME NOT= (STARG39+5.) THEN GO TO 398
    PC$76=PC$76+(106.*A(1939))
    PC$H=PC$H+IG39$+J1L*IG39$+J2L*IG39$+J3L*IG39$+
            J4L*IG39$+J5L*IG39$+J6L*IG39$+IDCG39$+J1L*IDCG39$+
            J2L*IDCG39$+J3L*IDCG39$+J4L*IDCG39$+J5L*IDCG39$+J6L*IDCG39$
    SECAC=SECAC+3420.
    SCC=SCC+500.
398 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
400 IF RTIME>(STARG40+6.) THEN GO TO 408
    IF RTIME=STARG40 THEN G40$76=5.*A(1940)
    IF RTIME=(STARG40+1.) THEN G40$76=15.*A(1940)
    IF RTIME=(STARG40+2.) THEN G40$76=30.*A(1940)
    IF RTIME=(STARG40+3.) THEN G40$76=40.*A(1940)
    IF RTIME=(STARG40+4.) THEN G40$76=45.*A(1940)
    IF RTIME=(STARG40+5.) THEN G40$76=50.*A(1940)
    IF RTIME=(STARG40+6.) THEN G40$76=15.*A(1940)
    IG40$=PEXOG/2.11*G40$76
    IDCG40$=A(1872)*((.5*IG40$)+J1L*IG40$+J2L*IG40$+
            J3L*IG40$+J4L*IG40$+J5L*IG40$+J6L*IG40$)
    IDC$=IDC$+IDCG40$
    IF RTIME NOT= (STARG40+6.) THEN GO TO 408
    PC$76=PC$76+(200.*A(1940))
    PC$H=PC$H+IG40$+J1L*IG40$+J2L*IG40$+J3L*IG40$+
            J4L*IG40$+J5L*IG40$+J6L*IG40$+IDCG40$+J1L*IDCG40$+
            J2L*IDCG40$+J3L*IDCG40$+J4L*IDCG40$+J5L*IDCG40$+J6L*IDCG40$
    SECAC=SECAC+4790.
    SCC=SCC+700.
408 IF A(2011) NOT= 0. THEN GO TO 410
    IF A(2010) NOT= 0. THEN GO TO 505
410 IF RTIME>(STARG41+5.) THEN GO TO 418
    IF RTIME=STARG41 THEN G41$76=7.*A(1941)
    IF RTIME=(STARG41+1.) THEN G41$76=20.*A(1941)
    IF RTIME=(STARG41+2.) THEN G41$76=30.*A(1941)
    IF RTIME=(STARG41+3.) THEN G41$76=35.*A(1941)
    IF RTIME=(STARG41+4.) THEN G41$76=50.*A(1941)
    IF RTIME=(STARG41+5.) THEN G41$76=15.*A(1941)
    IG41$=PEXOG/2.11*G41$76
    IDCG41$=A(1872)*((.5*IG41$)+J1L*IG41$+J2L*IG41$+
            J3L*IG41$+J4L*IG41$+J5L*IG41$+J6L*IG41$)
    IDC$=IDC$+IDCG41$
    IF RTIME NOT= (STARG41+5.) THEN GO TO 418
    PC$76=PC$76+(157.*A(1941))
    PC$H=PC$H+IG41$+J1L*IG41$+J2L*IG41$+J3L*IG41$+
            J4L*IG41$+J5L*IG41$+J6L*IG41$+IDCG41$+J1L*IDCG41$+
            J2L*IDCG41$+J3L*IDCG41$+J4L*IDCG41$+J5L*IDCG41$+J6L*IDCG41$
    SECAC=SECAC+4790.
    SCC=SCC+700.
418 IF A(2011) NOT= 0. THEN GO TO 420
    IF A(2010) NOT= 0. THEN GO TO 505
420 IF RTIME>(STARG42+5.) THEN GO TO 428
    IF RTIME=STARG42 THEN G42$76=7.*A(1942)
    IF RTIME=(STARG42+1.) THEN G42$76=20.*A(1942)
    IF RTIME=(STARG42+2.) THEN G42$76=30.*A(1942)
    IF RTIME=(STARG42+3.) THEN G42$76=35.*A(1942)
    IF RTIME=(STARG42+4.) THEN G42$76=50.*A(1942)
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    IF RTIME=(STARG42+5.) THEN G42$76=15.*A(1942)
    IG42$=PEXOG/2.11*G42$76
    IDCG42$=A(1872)*((.5*IG42$)+J1L*IG42$+J2L*IG42$+
            J3L*IG42$+J4L*IG42$+J5L*IG42$+J6L*IG42$)
    IDC$=IDC$+IDCG42$
    IF RTIME NOT= (STARG42+5.) THEN GO TO 428
    PC$76=PC$76+(157.*A(1942))
    PC$H=PC$H+IG42$+J1L*IG42$+J2L*IG42$+J3L*IG42$+
            J4L*IG42$+J5L*IG42$+J6L*IG42$+IDCG42$+J1L*IDCG42$+
            J2L*IDCG42$+J3L*IDCG42$+J4L*IDCG42$+J5L*IDCG42$+J6L*IDCG42$
    SECAC=SECAC+4790.
    SCC=SCC+700.
428 IF A(2011) NOT= 0. THEN GO TO 430
    IF A(2010) NOT= 0. THEN GO TO 505
430 IF RTIME>(STARG43+5.) THEN GO TO 438
    IF RTIME=STARG43 THEN G43$76=7.*A(1943)
    IF RTIME=(STARG43+1.) THEN G43$76=20.*A(1943)
    IF RTIME=(STARG43+2.) THEN G43$76=30.*A(1943)
    IF RTIME=(STARG43+3.) THEN G43$76=35.*A(1943)
    IF RTIME=(STARG43+4.) THEN G43$76=50.*A(1943)
    IF RTIME=(STARG43+5.) THEN G43$76=15.*A(1943)
    IG43$=PEXOG/2.11*G43$76
    IDCG43$=A(1872)*((.5*IG43$)+J1L*IG43$+J2L*IG43$+
            J3L*IG43$+J4L*IG43$+J5L*IG43$+J6L*IG43$)
    IDC$=IDC$+IDCG43$
    IF RTIME NOT= (STARG43+5.) THEN GO TO 438
    PC$76=PC$76+(157.*A(1943))
    PC$H=PC$H+IG43$+J1L*IG43$+J2L*IG43$+J3L*IG43$+
            J4L*IG43$+J5L*IG43$+J6L*IG43$+IDCG43$+J1L*IDCG43$+
            J2L*IDCG43$+J3L*IDCG43$+J4L*IDCG43$+J5L*IDCG43$+J6L*IDCG43$
    SECAC=SECAC+4790.
    SCC=SCC+700.
438 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
440 IF RTIME<STARG46 THEN GO TO 460
    IF RTIME>(STARG46+6.) THEN GO TO 448
    IF RTIME=STARG46 THEN G44$76=3.*A(1944)
    IF RTIME=(STARG46+1.) THEN G44$76=8.*A(1944)
    IF RTIME=(STARG46+2.) THEN G44$76=19.*A(1944)
    IF RTIME=(STARG46+3.) THEN G44$76=35.*A(1944)
    IF RTIME=(STARG46+4.) THEN G44$76=45.*A(1944)
    IF RTIME=(STARG46+5.) THEN G44$76=45.*A(1944)
    IF RTIME=(STARG46+6.) THEN G44$76=45.*A(1944)
    IG44$=PEXOG/2.11*G44$76
    IDCG44$=A(1872)*((.5*IG44$)+J1L*IG44$+J2L*IG44$+
            J3L*IG44$+J4L*IG44$+J5L*IG44$+J6L*IG44$)
    IDC$=IDC$+IDCG44$
    IF RTIME NOT= (STARG46+6.) THEN GO TO 448
    PC$76=PC$76+(200.*A(1944))
    PC$H=PC$H+IG44$+J1L*IG44$+J2L*IG44$+J3L*IG44$+
            J4L*IG44$+J5L*IG44$+J6L*IG44$+IDCG44$+J1L*IDCG44$+
            J2L*IDCG44$+J3L*IDCG44$+J4L*IDCG44$+J5L*IDCG44$+J6L*IDCG44$
    SEKAC=SEKAC+4790.
    SCK=SCK+700.
448 IF A(2011) NOT= 0. THEN GO TO 450
    IF A(2010) NOT= 0. THEN GO TO 505
450 IF RTIME<STARG45 THEN GO TO 458
    IF RTIME>(STARG45+6.) THEN GO TO 458
    IF RTIME=STARG45 THEN G45$76=2.*A(1945)
    IF RTIME=(STARG45+1.) THEN G45$76=5.*A(1945)
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    IF RTIME=(STARG45+2.) THEN G45$76=10.*A(1945)
    IF RTIME=(STARG45+3.) THEN G45$76=15.*A(1945)
    IF RTIME=(STARG45+4.) THEN G45$76=25.*A(1945)
    IF RTIME=(STARG45+5.) THEN G45$76=30.*A(1945)
    IF RTIME=(STARG45+6.) THEN G45$76=40.*A(1945)
    IG45$=PEXOG/2.11*G45$76
    IDCG45$=A(1872)*((.5*IG45$)+J1L*IG45$+J2L*IG45$+
            J3L*IG45$+J4L*IG45$+J5L*IG45$+J6L*IG45$)
    IDC$=IDC$+IDCG45$
    IF RTIME NOT= (STARG45+6.) THEN GO TO 458
    PC$76=PC$76+(127.*A(1945))
    PC$H=PC$H+IG45$+J1L*IG45$+J2L*IG45$+J3L*IG45$+
            J4L*IG45$+J5L*IG45$+J6L*IG45$+IDCG45$+J1L*IDCG45$+
            J2L*IDCG45$+J3L*IDCG45$+J4L*IDCG45$+J5L*IDCG45$+J6L*IDCG45$
    SEKAC=SEKAC+4790.
    SCK=SCK+700.
458 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
460 IF RTIME<STARG46 THEN GO TO 468
    IF RTIME>(STARG46+6.) THEN GO TO 468
    IF RTIME=STARG46 THEN G46$76=2.*A(1946)
    IF RTIME=(STARG46+1.) THEN G46$76=5.*A(1946)
    IF RTIME=(STARG46+2.) THEN G46$76=10.*A(1946)
    IF RTIME=(STARG46+3.) THEN G46$76=15.*A(1946)
    IF RTIME=(STARG46+4.) THEN G46$76=25.*A(1946)
    IF RTIME=(STARG46+5.) THEN G46$76=30.*A(1946)
    IF RTIME=(STARG46+6.) THEN G46$76=40.*A(1946)
    IG46$=PEXOG/2.11*G46$76
    IDCG46$=A(1872)*((.5*IG46$)+J1L*IG46$+J2L*IG46$+
            J3L*IG46$+J4L*IG46$+J5L*IG46$+J6L*IG46$)
    IDC$=IDC$+IDCG46$
    IF RTIME NOT= (STARG46+6.) THEN GO TO 468
    PC$76=PC$76+(127.*A(1946))
    PC$H=PC$H+IG46$+J1L*IG46$+J2L*IG46$+J3L*IG46$+
            J4L*IG46$+J5L*IG46$+J6L*IG46$+IDCG46$+J1L*IDCG46$+
            J2L*IDCG46$+J3L*IDCG46$+J4L*IDCG46$+J5L*IDCG46$+J6L*IDCG46$
    SEKAC=SEKAC+4790.
    SCK=SCK+700.
468 IF A(2011) NOT= 0. THEN GO TO 505
    IF A(2010) NOT= 0. THEN GO TO 505
470 IF STARG47=0. THEN GO TO 505

  THE FOLLOWING SECTION AGGREGATES THE KEY FINANCIAL AND ENGINEERING
            VARIABLES FOR ALL THE GENERATION PROJECTS

  IGEN$76 - INVESTMENT IN GENERATION PROJECTS ($76)
505 IGEN$76=G1$76+G2$76+G3$76+G4$76+G5$76+G6$76+G7$76+G8$76+G9$76+
            G10$76+G11$76+G12$76+G13$76+G14$76+G15$76+G16$76+G17$76+G18$76+
            G19$76+G20$76+G21$76+G22$76+G23$76+G24$76+G25$76+G26$76+G27$76+
            G28$76+G29$76+G30$76+G31$76+G32$76+G33$76+G34$76+G35$76+G36$76+
            G37$76+G38$76+G39$76+G40$76+G41$76+G42$76+G43$76+G44$76+G45$76+
            G46$76+G47$76+G48$76+G49$76+G50$76

 IGEN$ - INVESTMENT IN GENERATION PROJECTS
    IGEN$=PEXOG/2.11*IGEN$76

  SENHCC1 - ENERGY GENERATION CAPACITY FROM HYDRO-ELECTRIC
            SOURCES DURING CRITICAL RAINFALL PERIOD AT END OF EACH YEAR
    IF RTIME=75. THEN SENHCC1=19903.
    IF RTIME>=76. THEN SENHCC1=J1L*SENHCC1+SEHCC
```

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SENERHCC - AVERAGE ENERGY GENERATION CAPACITY FROM HYDRO
            SOURCES DURING CRITICAL RAINFALL PERIOD
  IF RTIME=75. THEN SENERHCC=19903.
  IF RTIME>=76. THEN SENERHCC=J1L*SENHCC1+(.5*SEHCC)

SENHAC1 - ENERGY GENERATION CAPACITY FROM HYDRO-ELECTRIC
            SOURCES DURING AVERAGE RAINFALL PERIOD AT END OF EACH YEAR
  IF RTIME=75. THEN SENHAC1=21800.
  IF RTIME>=76. THEN SENHAC1=J1L*SENHAC1+SEHAC

SENERHAC - AVERAGE ENERGY GENERATION CAPACITY FROM HYRDO-
            ELECTRIC SOURCES DURING AVERAGE RAINFALL PERIOD
  IF RTIME=75. THEN SENERHAC=21800.
  IF RTIME>=76. THEN SENERHAC=J1L*SENHAC1+(.5*SEHAC)

SENGAC1 - ENERGY GENERATION CAPACITY FROM GAS TURBINES
            AT YEAR END
  IF RTIME=75. THEN J1L*SENGAC1=1476.
  IF RTIME>=75. THEN SENGAC1=J1L*SENGAC1+SEGAC

SENERGAC - AVERAGE ENERGY GENERATION CAPACITY FROM GAS TURBINES
  SENERGAC=J1L*SENGAC1+(.5*SEGAC)

SENCAC1 - ENERGY GENERATION CAPACITY FROM HAT CREEK AT YEAR END
  SENCAC1=J1L*SENCAC1+SECAC

SENERCAC - AVERAGE ENERGY GENERATION CAPACITY FROM HAT CREEK
  SENERCAC=J1L*SENCAC1+(.5*SECAC)

SENKAC1 - ENERGY GENERATION CAPACITY FROM EAST KOOTENAY COAL AT
            YEAR END
  SENKAC1=J1L*SENKAC1+SEKAC
  SENERKAC=J1L*SENKAC1+(.5*SEKAC)

SCAP_'S - VARIOUS CATEGORIES OF ENERGY CAPACITY CAPABILITY
  IF RTIME=75. THEN SCAPH=4186.
  IF RTIME>75. THEN SCAPH=J1L*SCAPH+SCH
  SCAPB=900.
  IF RTIME=75. THEN SCAPG=327.
  IF RTIME>75. THEN SCAPG=J1L*SCAPG+SCG
  SCAPC=J1L*SCAPC+SCC
  SCAPK=J1L*SCAPK+SCK

KPIS_$76'S - VARIOUS CATEGORIES OF POST-74 GENERATION
            PLANT IN SERVICE AT YEAR END ($76)
  KPISH$76=J1L*KPISH$76+PH$76
  KPISG$76=J1L*KPISG$76+PG$76
  KPISC$76=J1L*KPISC$76+PC$76
  KPISK$76=J1L*KPISK$76+PK$76

KPIS_$H - VARIOUS CATEGORIES OF POST-74 GENERATION
            PLANT IN SERVICE
  KPISH$H=J1L*KPISH$H+PH$H
  KPISG$H=J1L*KPISG$H+PG$H
  KPISC$H=J1L*KPISC$H+PC$H
  IF A(2011)=0. THEN GO TO 508
  IF A(2011)=1. THEN GO TO 590
  IF A(2011)=6. THEN GO TO 580
  IF A(2011)=7. THEN GO TO 710
  IF A(2011)=8. THEN GO TO 560
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    IF A(2011)=11. THEN GO TO 810
    IF A(2011)=16. THEN GO TO 860
    IF A(2011)=17. THEN GO TO 900
    IF A(2011)=21. THEN GO TO 940
    IF A(2011) NOT= 0. THEN GO TO 1010
508 IF A(2010) NOT= 0. THEN GO TO 1010

  CALCULATE FINANCIAL AND ENGINEERING INFORMATION FROM KNOWLEDGE
              ABOUT STARTING DATE OF EACH MAJOR ASSOCIATED TRANSMISSION
              PROJECT. CALCULATIONS PARALLEL THOSE FOR GENERATION
              PROJECTS(SEE STATEMENT 90)


510 IF RTIME>START1 THEN GO TO 520
    IF RTIME=START1 THEN T1$76=13.8*A(1951)
    IT1$=PEXOG/2.11*T1$76
    IDCT1$=5.
    IDC$=IDC$+IDCT1$
520 IF RTIME>START2 THEN GO TO 530
    IF RTIME=START2 THEN T2$76=11.4*A(1952)
    IT2$=PEXOG/2.11*T2$76
    IF RTIME=(START2-1.) THEN IDCT2$=1.5
    IF RTIME=START2 THEN IDCT2$=3.5
    IDC$=IDC$+IDCT2$
    IF RTIME NOT= START2 THEN GO TO 530
    PT$76=PT$76+(20.6*A(1952))
    PT$H=PT$H+30.9
530 IF RTIME>(START3+1.) THEN GO TO 540
    IF RTIME=START3 THEN T3$76=42.*A(1953)
    IF RTIME=(START3+1.) THEN T3$76=46.5*A(1953)
    IT3$=PEXOG/2.11*T3$76
    IF RTIME=START3 THEN IDCT3$=3.0
    IF RTIME=(START3+1.) THEN IDCT3$=5.0
    IDC$=IDC$+IDCT3$
    IF RTIME NOT= (START3+1.) THEN GO TO 540
    PT$76=PT$76+(85.*A(1953))
    PT$H=PT$H+117.
540 IF RTIME>(START4+1.) THEN GO TO 560
    IF RTIME=START4 THEN T4$76=15.2*A(1954)
    IT4$=PEXOG/2.11*T4$76
    IF RTIME=(START4-3.) THEN IDCT4$=.5
    IF RTIME=(START4-2.) THEN IDCT4$=1.
    IF RTIME=(START4-1.) THEN IDCT4$=1.5
    IF RTIME=START4 THEN IDCT4$=3.
    IDC$=IDC$+IDCT4$
    IF RTIME NOT= START4 THEN GO TO 560
    PT$76=PT$76+(85.*A(1954))
    PT$H=PT$H+117.
560 IF RTIME>(START6+4.) THEN GO TO 578
    IF RTIME=START6 THEN T6$76=3.*A(1956)
    IF RTIME=(START6+1.) THEN T6$76=3.6*A(1956)
    IF RTIME=(START6+2.) THEN T6$76=14.2*A(1956)
    IF RTIME=(START6+3.) THEN T6$76=16.8*A(1956)
    IF RTIME=(START6+4.) THEN T6$76=8.9*A(1956)
    IT6$=PEXOG/2.11*T6$76
    IDCT6$=A(1872)*((.5*IT6$)+J1L*IT6$+J2L*IT6$+
            J3L*IT6$+J4L*IT6$+J5L*IT6$+J6L*IT6$)
    IDC$=IDC$+IDCT6$
    IF RTIME NOT= (START6+4.) THEN GO TO 578
    PT$76=PT$76+(46.5*A(1956))
```

```
    PT$H=PT$H+IT6$+J1L*IT6$+J2L*IT6$+J3L*IT6$+
            J4L*IT6$+J5L*IT6$+J6L*IT6$+IDCT6$+J1L*IDCT6$+
            J2L*IDCT6$+J3L*IDCT6$+J4L*IDCT6$+J5L*IDCT6$+J6L*IDCT6$
578 IF A(2011) NOT= 0. THEN GO TO 1005
580 IF RTIME>(START8+5.) THEN GO TO 588
    IF RTIME=START8 THEN T8$76=2.2*A(1958)
    IF RTIME=(START8+1.) THEN T8$76=8.*A(1958)
    IF RTIME=(START8+2.) THEN T8$76=4.3*A(1958)
    IF RTIME=(START8+3.) THEN T8$76=16.9*A(1958)
    IF RTIME=(START8+4.) THEN T8$76=34.9*A(1958)
    IF RTIME=(START8+5.) THEN T8$76=16.1*A(1958)
    IT8$=PEXOG/2.11*T8$76
    IDCT8$=A(1872)*((.5*IT8$)+J1L*IT8$+J2L*IT8$+
            J3L*IT8$+J4L*IT8$+J5L*IT8$+J6L*IT8$)
    IDC$=IDC$+IDCT8$
    IF RTIME NOT= (START8+5.) THEN GO TO 588
    PT$76=PT$76+(82.4*A(1958))
    PT$H=PT$H+IT8$+J1L*IT8$+J2L*IT8$+J3L*IT8$+
            J4L*IT8$+J5L*IT8$+J6L*IT8$+IDCT8$+J1L*IDCT8$+
            J2L*IDCT8$+J3L*IDCT8$+J4L*IDCT8$+J5L*IDCT8$+J6L*IDCT8$
588 IF A(2011) NOT= 0. THEN GO TO 1005
590 IF RTIME>(START9+6.) THEN GO TO 600
    IF RTIME=START9 THEN T9$76=7.*A(1959)
    IF RTIME=(START9+1.) THEN T9$76=4.1*A(1959)
    IF RTIME=(START9+2.) THEN T9$76=1.2*A(1959)
    IF RTIME=(START9+3.) THEN T9$76=.7*A(1959)
    IF RTIME=(START9+4.) THEN T9$76=2.8*A(1959)
    IF RTIME=(START9+5.) THEN T9$76=5.7*A(1959)
    IF RTIME=(START9+6.) THEN T9$76=1.8*A(1959)
    IT9$=PEXOG/2.11*T9$76
    IDCT9$=A(1872)*((.5*IT9$)+J1L*IT9$+J2L*IT9$+
            J3L*IT9$+J4L*IT9$+J5L*IT9$+J6L*IT9$)
    IDC$=IDC$+IDCT9$
    IF RTIME NOT= (START9+6.) THEN GO TO 600
    PT$76=PT$76+(23.3*A(1959))
    PT$H=PT$H+IT9$+J1L*IT9$+J2L*IT9$+J3L*IT9$+
            J4L*IT9$+J5L*IT9$+J6L*IT9$+IDCT9$+J1L*IDCT9$+
            J2L*IDCT9$+J3L*IDCT9$+J4L*IDCT9$+J5L*IDCT9$+J6L*IDCT9$
600 IF RTIME>(START10+5.) THEN GO TO 708
    IF RTIME=START10 THEN T10$76=1.*A(1960)
    IF RTIME=(START10+1.) THEN T10$76=1.*A(1960)
    IF RTIME=(START10+2.) THEN T10$76=3.*A(1960)
    IF RTIME=(START10+3.) THEN T10$76=5.5*A(1960)
    IF RTIME=(START10+4.) THEN T10$76=6.7*A(1960)
    IF RTIME=(START10+5.) THEN T10$76=2.8*A(1960)
    IT10$=PEXOG/2.11*T10$76
    IDCT10$=A(1872)*((.5*IT10$)+J1L*IT10$+J2L*IT10$+
            J3L*IT10$+J4L*IT10$+J5L*IT10$+J6L*IT10$)
    IDC$=IDC$+IDCT10$
    IF RTIME NOT= (START10+5.) THEN GO TO 708
    PT$76=PT$76+(20.*A(1960))
    PT$H=PT$H+IT10$+J1L*IT10$+J2L*IT10$+J3L*IT10$+
            J4L*IT10$+J5L*IT10$+J6L*IT10$+IDCT10$+J1L*IDCT10$+
            J2L*IDCT10$+J3L*IDCT10$+J4L*IDCT10$+J5L*IDCT10$+J6L*IDCT10$
708 IF A(2011) NOT= 0. THEN GO TO 1005
710 IF START21=0. THEN GO TO 808
    IF RTIME>(START21+4.) THEN GO TO 808
    IF RTIME=START21 THEN T21$76=4.9*A(1971)
    IF RTIME=(START21+1.) THEN T21$76=5.9*A(1971)
    IF RTIME=(START21+2.) THEN T21$76=23.2*A(1971)
```

```
    IF RTIME=(START21+3.) THEN T21$76=27.4*A(1971)
    IF RTIME=(START21+4.) THEN T21$76=14.6*A(1971)
    IT21$=PEXOG/2.11*T21$76
    IDCT21$=A(1872)*((.5*IT21$)+J1L*IT21$+J2L*IT21$+
            J3L*IT21$+J4L*IT21$+J5L*IT21$+J6L*IT21$)
    IDC$=IDC$+IDCT21$
    IF RTIME NOT= (START21+4.) THEN GO TO 808
    PT$76=PT$76+(76.*A(1971))
    PT$H=PT$H+IT21$+J1L*IT21$+J2L*IT21$+J3L*IT21$+
            J4L*IT21$+J5L*IT21$+J6L*IT21$+IDCT21$+J1L*IDCT21$+
            J2L*IDCT21$+J3L*IDCT21$+J4L*IDCT21$+J5L*IDCT21$+J6L*IDCT21$
808 IF A(2011) NOT= 0. THEN GO TO 1005
810 IF RTIME>(START31+2.) THEN GO TO 858
    IF RTIME=START31 THEN T31$76=.3*A(1981)
    IF RTIME=(START31+1.) THEN T31$76=1.8*A(1981)
    IF RTIME=(START31+2.) THEN T31$76=.9*A(1981)
    IT31$=PEXOG/2.11*T31$76
    IDCT31$=A(1872)*((.5*IT31$)+J1L*IT31$+J2L*IT31$+
            J3L*IT31$+J4L*IT31$+J5L*IT31$+J6L*IT31$)
    IDC$=IDC$+IDCT31$
    IF RTIME NOT= (START31+2.) THEN GO TO 858
    PT$76=PT$76+(3.*A(1981))
    PT$H=PT$H+IT31$+J1L*IT31$+J2L*IT31$+J3L*IT31$+
            J4L*IT31$+J5L*IT31$+J6L*IT31$+IDCT31$+J1L*IDCT31$+
            J2L*IDCT31$+J3L*IDCT31$+J4L*IDCT31$+J5L*IDCT31$+J6L*IDCT31$
858 IF A(2011) NOT= 0. THEN GO TO 1005
860 IF RTIME<START36 THEN GO TO 1005
    IF RTIME>(START36+6.) THEN GO TO 880
    IF RTIME=START36 THEN T36$76=2.3*A(1986)
    IF RTIME=(START36+1.) THEN T36$76=2.6*A(1986)
    IF RTIME=(START36+2.) THEN T36$76=.7*A(1986)
    IF RTIME=(START36+3.) THEN T36$76=8.5*A(1986)
    IF RTIME=(START36+4.) THEN T36$76=16.7*A(1986)
    IF RTIME=(START36+5.) THEN T36$76=5.8*A(1986)
    IF RTIME=(START36+6.) THEN T36$76=4.2*A(1986)
    IT36$=PEXOG/2.11*T36$76
    IDCT36$=A(1872)*((.5*IT36$)+J1L*IT36$+J2L*IT36$+
            J3L*IT36$+J4L*IT36$+J5L*IT36$+J6L*IT36$)
    IDC$=IDC$+IDCT36$
    IF RTIME NOT= (START36+6.) THEN GO TO 880
    PT$76=PT$76+(40.8*A(1986))
    PT$H=PT$H+IT36$+J1L*IT36$+J2L*IT36$+J3L*IT36$+
            J4L*IT36$+J5L*IT36$+J6L*IT36$+IDCT36$+J1L*IDCT36$+
            J2L*IDCT36$+J3L*IDCT36$+J4L*IDCT36$+J5L*IDCT36$+J6L*IDCT36$
880 IF RTIME>(START38+5.) THEN GO TO 898
    IF RTIME=START38 THEN T38$76=.4*A(1988)
    IF RTIME=(START38+1.) THEN T38$76=1.5*A(1988)
    IF RTIME=(START38+2.) THEN T38$76=.8*A(1988)
    IF RTIME=(START38+3.) THEN T38$76=3.1*A(1988)
    IF RTIME=(START38+4.) THEN T38$76=6.4*A(1988)
    IF RTIME=(START38+5.) THEN T38$76=2.9*A(1988)
    IT38$=PEXOG/2.11*T38$76
    IDCT38$=A(1872)*((.5*IT38$)+J1L*IT38$+J2L*IT38$+
            J3L*IT38$+J4L*IT38$+J5L*IT38$+J6L*IT38$)
    IDC$=IDC$+IDCT38$
    IF RTIME NOT= (START38+5.) THEN GO TO 898
    PT$76=PT$76+(15.1*A(1988))
    PT$H=PT$H+IT38$+J1L*IT38$+J2L*IT38$+J3L*IT38$+
            J4L*IT38$+J5L*IT38$+J6L*IT38$+IDCT38$+J1L*IDCT38$+
            J2L*IDCT38$+J3L*IDCT38$+J4L*IDCT38$+J5L*IDCT38$+J6L*IDCT38$
```

```
898 IF A(2011) NOT= 0. THEN GO TO 1005
900 IF RTIME>(START40+6.) THEN GO TO 938
    IF RTIME<START40 THEN GO TO 1005
    IF RTIME=START40 THEN T40$76=1.*A(1990)
    IF RTIME=(START40+1.) THEN T40$76=.8*A(1990)
    IF RTIME=(START40+2.) THEN T40$76=1.4*A(1990)
    IF RTIME=(START40+3.) THEN T40$76=2.7*A(1990)
    IF RTIME=(START40+4.) THEN T40$76=3.7*A(1990)
    IF RTIME=(START40+5.) THEN T40$76=6.9*A(1990)
    IF RTIME=(START40+6.) THEN T40$76=7.3*A(1990)
    IT40$=PEXOG/2.11*T40$76
    IDCT40$=A(1872)*((.5*IT40$)+J1L*IT40$+J2L*IT40$+
            J3L*IT40$+J4L*IT40$+J5L*IT40$+J6L*IT40$)
    IDC$=IDC$+IDCT40$
    IF RTIME NOT= (START40+6.) THEN GO TO 938
    PT$76=PT$76+(23.8*A(1990))
    PT$H=PT$H+IT40$+J1L*IT40$+J2L*IT40$+J3L*IT40$+
            J4L*IT40$+J5L*IT40$+J6L*IT40$+IDCT40$+J1L*IDCT40$+
            J2L*IDCT40$+J3L*IDCT40$+J4L*IDCT40$+J5L*IDCT40$+J6L*IDCT40$
938 IF A(2011) NOT= 0. THEN GO TO 1005
940 IF RTIME>(START44+6.) THEN GO TO 950
    IF RTIME<START44 THEN GO TO 1005
    IF RTIME=START44 THEN T44$76=.8*A(1994)
    IF RTIME=(START44+1.) THEN T44$76=2.9*A(1994)
    IF RTIME=(START44+2.) THEN T44$76=2.4*A(1994)
    IF RTIME=(START44+3.) THEN T44$76=5.4*A(1994)
    IF RTIME=(START44+4.) THEN T44$76=14.7*A(1994)
    IF RTIME=(START44+5.) THEN T44$76=14.*A(1994)
    IF RTIME=(START44+6.) THEN T44$76=7.6*A(1994)
    IT44$=PEXOG/2.11*T44$76
    IDCT44$=A(1872)*((.5*IT44$)+J1L*IT44$+J2L*IT44$+
            J3L*IT44$+J4L*IT44$+J5L*IT44$+J6L*IT44$)
    IDC$=IDC$+IDCT44$
    IF RTIME NOT= (START44+6.) THEN GO TO 950
    PT$76=PT$76+(62.8*A(1994))
    PT$H=PT$H+IT44$+J1L*IT44$+J2L*IT44$+J3L*IT44$+
            J4L*IT44$+J5L*IT44$+J6L*IT44$+IDCT44$+J1L*IDCT44$+
            J2L*IDCT44$+J3L*IDCT44$+J4L*IDCT44$+J5L*IDCT44$+J6L*IDCT44$
950 IF RTIME<START45 THEN GO TO 1005
    IF RTIME>(START45+4.) THEN GO TO 1005
    IF RTIME=START45 THEN T45$76=1.*A(1995)
    IF RTIME=(START45+1.) THEN T45$76=2.*A(1995)
    IF RTIME=(START45+2.) THEN T45$76=3.*A(1995)
    IF RTIME=(START45+3.) THEN T45$76=6.*A(1995)
    IF RTIME=(START45+4.) THEN T45$76=3.*A(1995)
    IT45$=PEXOG/2.11*T45$76
    IDCT45$=A(1872)*((.5*IT45$)+J1L*IT45$+J2L*IT45$+
            J3L*IT45$+J4L*IT45$+J5L*IT45$+J6L*IT45$)
    IDC$=IDC$+IDCT45$
    IF RTIME NOT= (START45+4.) THEN GO TO 1005
    PT$76=PT$76+(15.*A(1995))
    PT$H=PT$H+IT45$+J1L*IT45$+J2L*IT45$+J3L*IT45$+
            J4L*IT45$+J5L*IT45$+J6L*IT45$+IDCT45$+J1L*IDCT45$+
            J2L*IDCT45$+J3L*IDCT45$+J4L*IDCT45$+J5L*IDCT45$+J6L*IDCT45$
```

AGGREGATE FINANCIAL INFORMATION FOR ALL MAJOR ASSOCIATED TRANSMISSION PROJECTS

ITRS1$76 - INVESTMENT IN MAJOR ASSOCIATED TRANSMISSION PROJECTS ($76)

```
ITRS1$76=T1$76+T2$76+T3$76+T4$76+T6$76+T8$76+T9$76+T10$76+
          T21$76+T31$76+T36$76+T38$76+T40$76+T44$76+T45$76

 ITRS1$ - INVESTMENT IN MAJOR ASSOCIATED TRANSMISSION PROJECTS
   ITRS1$=PEXOG/2.11*ITRS1$76

 KPST1$76 - NEW MAJOR TRANSMISSION PLANT IN SERVICE ($76)
   KPST1$76=J1L*KPST1$76+PT$76

 KPIST1$H - NEW MAJOR TRANSMISSION PLANT IN SERVICE ($H)
   KPIST1$H=J1L*KPIST1$H+PT$H

 STPNOM - NOMINAL RATE OF SOCIAL TIME PREFERENCE
 STPNOM=(1.+A(1894))*(PEXOG/J1L*PEXOG)

 SENERHC - HYDRO-GENERATED ENERGY CAPACITY

  HERE IF AVERAGE RAINFALL PERIOD

   SENERHC=SENERHAC

  HERE IF CRITICAL RAINFALL PERIOD

   IF A(2007) NOT= 0. THEN SENERHC=SENERHCC

  SENERBC - BURRARD'S ENERGY CAPABILITY

   SENERBC=SENERBAC

  SENERCC - HAT CREEK COAL CAPABILITY

   SENERCC=SENERCAC

  SENERKC - EAST KOOTENAY COAL ENERGY CAPABILITY

   SENERKC=SENERKAC

  SENERGC - GAS TURBINES ENERGY CAPABILITY

   SENERGC=SENERGAC

  SCAPH - HYDRO GENERATION CAPACITY CAPABILITY

   SCAPH=SCAPH

  IGEN$74 - INVESTMENT IN GENERATION PROJECTS

   IGEN$76=IGEN$76

 KPIS_$76'S

   KPISH$76=KPISH$76

   KPISC$76=KPISC$76+KPISK$76

   KPISG$76=KPISG$76

 SENERCAP - TOTAL ENERGY CAPABILITY

   SENERCAP=SENERHC+SENERBC+SENERCC+SENERKC+SENERGC
```

```
  ITRS1$76=ITRS1$76
```

KPST1$76 - STOCK OF NEW MAJOR ASSOCIATED TRANSMISSION PROJECTS IN SERVICE

```
  KPST1$76=KPST1$76
```

SUBROUTINE COSTS

THIS SECTION TAKES INFORMATION SUPPLIED FROM THE PLANNING SECTION AND ALLOCATES THE ASSOCIATED OPERATING AND CAPITAL COSTS ACCORDING TO CONVENTIONAL ACCOUNTING TECHNIQUES

COPFIX$ - FIXED OPERATING COSTS FOR COMPLETE SYSTEM

```
  IF NTIME=75 THEN COPFIX$=108.6

  IF NTIME>=76 THEN COPFIX$=(108.6*PEXOG/1.95)+
          ((PEXOG/2.11)*A(1853)*(J1L*KPISH$76+
          (.4*(KPISH$76-J1L*KPISH$76))))+
          ((PEXOG/2.11)*A(1854)*(J1L*KPISC$76+
          (.4*(KPISC$76-J1L*KPISC$76))))+
          ((PEXOG/2.11)*A(1855)*(J1L*KPISG$76+
          (.4*(KPISG$76-J1L*KPISG$76))))+
          ((PEXOG/2.11)*A(1856)*(J1L*KPIST$76+
          (.4*(KPIST$76-J1L*KPIST$76))))+
          ((PEXOG/2.11)*A(1857)*(J1L*KPISD$76+
          (.4*(KPISD$76-J1L*KPISD$76))))
```

COPFIX1$ - FIXED OPERATING COSTS TO 230 KV LEVEL

```
  IF NTIME=75 THEN COPFIX1$=80.

  IF NTIME>=76 THEN COPFIX1$=(80.*PEXOG/1.95)+
          ((PEXOG/2.11)*A(1853)*(J1L*KPISH$76+
          (.4*(KPISH$76-J1L*KPISH$76))))+
          ((PEXOG/2.11)*A(1854)*(J1L*KPISC$76+
          (.4*(KPISC$76-J1L*KPISC$76))))+
          ((PEXOG/2.11)*A(1855)*(J1L*KPISG$76+
          (.4*(KPISG$76-J1L*KPISG$76))))+
          ((PEXOG/2.11)*A(1856)*(J1L*KPST3$76+
          (.4*(KPST3$76-J1L*KPST3$76))))+
          ((PEXOG/2.11)*A(1857)*(J1L*KPISM$76+
          (.4*(KPISM$76-J1L*KPISM$76))))
```

TWATER - WATER LICENCE COSTS

```
  IF NTIME=75 THEN TWATER=8.2
  IF NTIME>=76 THEN

          TWATER=(PEXOG/1.95)*A(1860)*(J1L*SCAPH+
          (.4*(SCAPH-J1L*SCAPH))+
```

```
         (PEXOG/1.95)*A(1861)*SENERH
```



```
COPVAR$ - VARIABLE OPERATING COSTS

   COPVAR$=(PEXOG/2.11)*A(1862)*SENERC+
           (PEXOG/2.11)*A(1863)*SENERK+
           (PEXOG/2.11)*A(1864)*SENERB+
           (PEXOG/2.11)*A(1865)*SENERG+
           (PEXOG/2.11)*A(1878)*SENERM

DEPREC$ - DEPRECIATION CHARGES

   IF NTIME=75 THEN DEPREC$=64.5

   IF NTIME>=76 THEN DEPREC$=64.5+
           A(1874)*(J1L*KPISH$H+(.4*(KPISH$H-J1L*KPISH$H)))+
           A(1875)*(J1L*KPISC$H+J1L*KPISG$H+
           (.4*(KPISC$H+KPISG$H-J1L*KPISC$H-J1L*KPISG$H)))+
           A(1876)*(J1L*KPIST$H+(.4*(KPIST$H-J1L*KPIST$H)))+
           A(1877)*(J1L*KPISD$H+(.4*(KPISD$H-J1L*KPISD$H)))

KDEP$76 - ACCUMULATED DEPRECIATION ON NEW NON-HYDRO-ELECTRIC
            FACILITIES FOR SCHOOL TAX PURPOSES

   IF NTIME=75 THEN DEPACC$H=0.

   IF NTIME>=76 THEN DEPACC$H=J1L*DEPACC$H+(2.11/PEXOG*
           (DEPREC$-64.5-(A(1874)*(J1L*KPISH$H+(.4*(KPISH$H-
           J1L*KPISH$H))))))

TSCHOOL - SCHOOL TAXES

   IF NTIME=75 THEN TSCHOOL=18.

   IF NTIME>=76 THEN TSCHOOL=(18.*PEXOG/1.95)+
           (A(1858)*(PEXOG/2.11*(J1L*KPIS$76-J1L*KPISH$76-
           J1L*DEPACC$H)))

TGRANTS - 'GRANTS'

   IF NTIME=75 THEN TGRANTS=3.3

   IF NTIME>=76 THEN TGRANTS=A(1859)*J1L*YTOT

TLAND - LAND TAXES

   IF NTIME=75 THEN TLAND=1.

   IF NTIME>=76 THEN TLAND=J1L*TLAND*(1.+(1.5*A(1972)))

TLOCAL - ALL LOCAL TAXES

   TLOCAL=TSCHOOL+TGRANTS+TLAND

INTEREST CHARGES


INTOLDB - ANNUAL INTEREST PAYMENTS REMAINING ON BONDS ISSUED PRIOR
            TO 1976
```

```
  IF NTIME=75 THEN INTOLDB=A(1867)*A(1868)*A(1869)

  IF NTIME=76 THEN INTOLDB=A(1867)*A(1868)*
         ((J1L*INTOLDB+25.)-(.5*INTRED$H)-(.5*J1L*INTRED$H))

  IF NTIME>=77 THEN INTOLDB=J1L*INTOLDB-(A(1867)*A(1868)*
         (.5*(INTRED$H+J1L*INTRED$H)))

LOLD$H - STOCK OF DEBT ISSUED PRIOR TO 1976 STILL OUTSTANDING AT
            END OF EACH PERIOD

  IF NTIME=75 THEN LOLD$H=2990.32

  IF NTIME>=76 THEN LOLD$H= J1L*LOLD$H-LOLDM$H

SFPAYMT$ - ANNUAL SINKING FUND PAYMENT AND ADDITIONAL FUNDS
            REQUIRED FOR BONDS MATURING BEFORE 1982

  IF NTIME=75 THEN SFPAYMT$=34.6*A(1867)

  IF NTIME=76 THEN SFPAYMT$=35.3*A(1867)

  IF NTIME=77 THEN SFPAYMT$=54.0*A(1867)

  IF NTIME=78 THEN SFPAYMT$=81.9*A(1867)

  IF NTIME=79 THEN SFPAYMT$=49.3*A(1867)

  IF NTIME=80 THEN SFPAYMT$=44.3*A(1867)

  IF NTIME=81 THEN SFPAYMT$=69.7*A(1867)

  IF NTIME>=82 THEN SFPAYMT$=
         (A(1870)*A(1867)*LOLD$H)+
         (A(1871)*J5L*LNEW$H)

FINREQ - FINANCIAL REQUIREMENTS

  FINREQ=I$+SFPAYMT$+(A(1867)*LMATWOSF)

FINREQB - FINANCIAL REQUIREMENTS TO BE MET BY DEBT FINANCING

  FINREQB=FINREQ-YTOT+COSTS$-DEPREC$

LNEW$H - STOCK OF POST-75 NEW BONDS OUTSTANDING

  IF NTIME=75 THEN LNEW$H=476.6

  IF NTIME>=76 THEN LNEW$H=J1L*LNEW$H+FINREQB

INT$ - TOTAL INTEREST CHARGES

  INT$=INTOLDB+(A(1868)*LNEW$H*A(1872))-IDC$

COSTS$ - TOTAL OPERATING AND CAPITAL COSTS

  COSTS$=COPFIX$+TLOCAL+TWATER+COPVAR$+DEPREC$+INT$

C1KWH$76 - NET COST PER KWH GENERATED
```

```
  C1KWH$76=(2.11*(COSTS$+(COVERAGE*INT$)-YEXPORT))/
        (SENER*PEXOG)
C2KWH$76 - COST PER KWH GENERATED

  C2KWH$76=(2.11*(COSTS$+(COVERAGE*INT$)))/(SENER*PEXOG)



THIS SECTION IS USED TO DO AN ECONOMIC ANALYSIS OF THE
           IMPLICATIONS FOR PRESENT AND FUTURE QUANTITIES AND COSTS OF
           CHANGES IN DEMAND GROWTH AND THE RESULTANT READJUSTMENT IN
           PROJECT PLANNING



CO1$76 - ANNUAL PRESENTLY UNCOMMITTED OPERATING COSTS (ALL
           VARIABLE AND POST-74 FIXED) TO SERVE LARGEST CUSTOMERS
  CO1$76=A(1861)*SENERH+A(1860)*SCAPH+A(1864)*
         SENERB+A(1862)*SENERC+A(1863)*SENERK+A(1865)*
         SENERG+A(1853)*KPISH$76+A(1854)*KPISC$76+A(1855)*
         KPISG$76+A(1856)*KPST3$76+A(1857)*KPISM$76-
         (A(1879)*DEXPORT)

CO2$76 - ANNUAL PRESENTLY UNCOMMITTED OPERATING COSTS (ALL
           VARIABLE AND POST-74 FIXED) TO SERVE SMALLEST CUSTOMERS
  CO2$76=CO1$76+A(1856)*KPST4$76+A(1857)*(KPISD$76-KPISM$76)

KPVELEC3 - PRESENT VALUE OF ACTUAL ENERGY PRODUCED (KWH)

  KPVELEC3=(1.+A(1894))*J1L*KPVELEC3+SENER*
         ((1.+A(1894))**.5)

  IF K7=M9 THEN KPVELEC3=KPVELEC3/((1.+A(1894))**(K7-2))

KPVELEC4 - PRESENT VALUE OF ACTUAL CAPACITY PRODUCED (MW)

  KPVELEC4=(1.+A(1894))*J1L*KPVELEC4+DPEAK*
         ((1.+A(1894))**.5)

  IF K7=M9 THEN KPVELEC4=KPVELEC4/((1.+A(1894))**(K7-2))

KELEC3 - STOCK OF CAPITAL TO SERVE LARGEST CUSTOMERS

  KELEC3=(J1L*KELEC3+IGEN$76+ITRS$76+ITRF1$76+
         (.5*IMISC$76))*(1.-A(1850))

KELEC4 - STOCK OF CAPITAL TO SERVE SMALLEST CUSTOMERS

  KELEC4=(J1L*KELEC4+IGEN$76+ITRS$76+ITRF$76+IDIST$76)*
         (1.-A(1850))

KPVC3$76 - PRESENT VALUE OF COSTS ASSOCIATED WITH SUPPLYING
           LARGEST CUSTOMERS

  KPVC3$76=(1.+A(1894))*J1L*KPVC3$76+(CO1$76+(A(1850)*
         (J1L*KELEC3+IGEN$76+ITRS$76+ITRF1$76+(.5*IMISC$76)))+
         ((A(1890)+A(1895))*.5*(KELEC3+J1L*KELEC3)))*
         ((1.+A(1894))**.5)

  IF K7=M9 THEN KPVC3$76=KPVC3$76/((1.+A(1894))**(K7-2))
```

KPVC4$76 - PRESENT VALUE OF COSTS ASSOCIATED WITH SUPPLYING SMALLEST CUSTOMERS

```
KPVC4$76=(1.+A(1894))*J1L*KPVC4$76+(CO2$76+(A(1850)*
        (J1L*KELEC4+IGEN$76+ITRS$76+ITRF$76+IDIST$76))+
        ((A(1890)+A(1895))*.5*(KELEC4+J1L*KELEC4)))*
        ((1.+A(1894))**.5)

IF K7=M9 THEN KPVC4$76=KPVC4$76/((1.+A(1894))**(K7-2))
```

SUBROUTINE RATES

THIS SECTION CALCULATES REVENUES AND RATES THAT ARE ESTABLISHED BY B C HYDRO IN RESPONSE TO THE COSTS FACING IT AND ITS FINANCIAL POLICIES

DETERMINE REVENUES FROM ELECTRICITY SALES

YRES - REVENUE FROM RESIDENTIAL SALES

```
YRES=PRES*DRES
```

YGEN - REVENUE FROM GENERAL SALES

```
YGEN=PGEN*DGEN
```

YBULK - REVENUE FROM BULK SALES

```
YBULK=PBULK*DBULK
```

YWKPL - REVENUE FROM WKPL SALES

```
YWKPL=PWKPL*DWKPL
```

YEXPORT - REVENUE FROM EXPORT SALES

```
YEXPORT=PEXPORT*DEXPORT
```

YTOT - TOTAL REVENUES

```
YTOT=YRES+YGEN+YBULK+YWKPL+YEXPORT
```

MISS- FRACTION OF REVENUE SURPLUS/DEFICIT

```
MISS=(COSTS$+(COVERAGE*INT$)-YTOT)/
        (YTOT-YEXPORT)
```

DETERMINE AVERAGE RATE LEVELS ($/KWH)

```
PRES - AVERAGE RESIDENTIAL RATE
  IF(NTIME.EQ.75) PRES=.023
  IF(NTIME.EQ.76) PRES=.027
  IF(NTIME.GE.77) PRES=J1L*PRES*(1.+MISS)
PGEN - AVERAGE GENERAL RATE
  IF(NTIME.EQ.75) PGEN=.020
  IF(NTIME.EQ.76) PGEN=.023
  IF(NTIME.EQ.77) PGEN=.026
  IF(NTIME.GE.78) PGEN=J1L*PGEN*(1.+MISS)
PBULK - AVERAGE BULK RATE
  IF(NTIME.EQ.75) PBULK=.007
  IF(NTIME.EQ.76) PBULK=.010
  IF(NTIME.EQ.77) PBULK=.011
  IF(NTIME.EQ.78) PBULK=.012
  IF(NTIME.EQ.79) PBULK=.0134
  IF(NTIME.GE.80) PBULK=J1L*PBULK*(1.+MISS)
PWKPL - AVERAGE WEST KOOTENAY POWER AND LIGHT RATE
  IF(NTIME.EQ.75) PWKPL=.0146
  IF(NTIME.EQ.76) PWKPL=.0186
  IF(NTIME.EQ.77) PWKPL=.0195
  IF(NTIME.GE.78) PWKPL=J1L*PWKPL*(1.+MISS)
PEXPORT - AVERAGE EXPORT PRICE
  IF(NTIME.GE.75) PEXPORT=A(1879)*(PEXOG/1.77)
CONVERT CURRENT DOLLAR RATES TO $76 RATES
  PRES$76=PRES*2.11/PEXOG
  PGEN$76=PGEN*2.11/PEXOG
  PBULK$76=PBULK*2.11/PEXOG
  PWKPL$76=PWKPL*2.11/PEXOG
  PEXP$76=A(1879)
YRESMCP - REVENUE FROM RESIDENTIAL SALES UNDER FULL MCP
```

```
  YRESMCP=A(2014)*PEXOG/2.11*DRES/1000.

YGENMCP - REVENUE FROM GENERAL SALES UNDER FULL MCP

  YGENMCP=A(2016)*PEXOG/2.11*DGEN/1000.

YBULKMCP - REVENUE FROM BULK SALES UNDER FULL MCP

  YBULKMCP=A(2018)*PEXOG/2.11*DBULK/1000.

YSURPMCP - ADDITIONAL B.C. HYDRO NET INCOME UNDER FULL MCP

  YSURPMCP=YRESMCP+YGENMCP+YBULKMCP+YWKPL+YEXPORT
          -COSTS$-(COVERAGE*INT$)

YTOTSURP - TOTAL B.C. HYDRO NET INCOME UNDER FULL MCP

  YTOTSURP=YSURPMCP+(COVERAGE*INT$)

YTOTMCP - TOTAL REVENUE FROM SALES UNDER FULL MCP

  YTOTMCP=YRESMCP+YGENMCP+YBULKMCP+YWKPL+YEXPORT

  IF(NTIME.LT.81) YTOTMCP=YTOT
```